CPUC Self-Generation Incentive Program Fourth-Year Impact Report

Final Report

Submitted to:

Southern California Edison and
The Self-Generation Incentive Program Working Group

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Executive Summary

1.1 Introduction

In response to Assembly Bill 970 which required the California Public Utilities Commission (CPUC) to initiate certain load control and distributed generation program activities, on March 27, 2001, the CPUC issued Decision 01-03-073 (D.01-03-073). This Decision mandated implementation across the service territories of California's investor-owned utilities (IOUs) of a self-generation program designed to produce significant public (e.g., environmental, energy distribution system) benefits for all ratepayers, including gas ratepayers. To meet this mandate, the California Self-Generation Incentive Program (SGIP) was created to offer financial incentives to customers of IOUs who install certain types of distributed generation facilities to meet all or a portion of their energy needs. The first SGIP application was accepted in July 2001 and the program is scheduled to continue offering incentives for completed projects through the end of 2007.

This report provides the basis and findings of an impact evaluation of the fourth year of this program that addresses calendar year 2004. This evaluation covers all SGIP projects coming on-line before January 1, 2005, representing a total of 116 MW.[1] Summary results and key findings presented below will contribute significantly to the overall evaluation plan for the SGIP. That overall plan includes evaluations of process, impact, cost-effectiveness.

1.2 Electric Demand Impact

The specific technologies eligible for the SGIP's financial support are identified in Table 1-1 along with a summary of program demand impact coincident with the CAISO 2004 system peak. This peak reached a maximum value of 45,562 MW on September 8 during the hour from 3:00 p.m. to 4:00 p.m. (PDT). The total on-line capacity of the 388 known operational SGIP projects exceeded 103 MW. The total impact of the SGIP coincident with the CAISO

[1] A total of 116 MW of SGIP Complete and Active projects were determined to be on-line as of December 31, 2004. However, many projects entering the SGIP during 2001-2004 remain Active in the program but are not yet on-line. These Active projects are in various stages of development, including design, financing, procurement, construction and commissioning. Some of the Active projects are on a wait list. Current program records indicate that the on-line capacity corresponding to all PY01-PY04 SGIP projects may eventually total as much as 277 MW, subject to program funding constraints.

peak hour load is estimated at just under 55 MW (i.e., an average of 0.53 kW of peak demand impact per kilowatt of on-line SGIP project capacity). The 0.39 kWp/kW unit demand impact of PV systems is strongly influenced by the late afternoon timing of the CAISO system peak. The 0.58 kWp/kW unit demand impact of engines, microturbines, and gas turbines is strongly influenced by the 26% of systems that were idle and not producing power on the date of the system peak.

Table 1-1: Program Electric Impact Coincident with 2004 CAISO Peak Load

Incentive Level	Technology	On-Line Systems (n)	On-Line Capacity (kW)	Peak Demand Impact (kW_P)	Unit Demand Impact (kW_P/kW)
1	Solar Photovoltaic (PV)	235	25,365	9,938	0.39
	Wind Turbine	1	950	0	0.00
2	Fuel Cell (natural gas)	2	800	744	0.93
3, 3-N, & 3-R	Engine, Microturbine, or Gas Turbine	150	75,930	44,115	0.58
Total		**388**	**103,045**	**54,797**	**0.53**

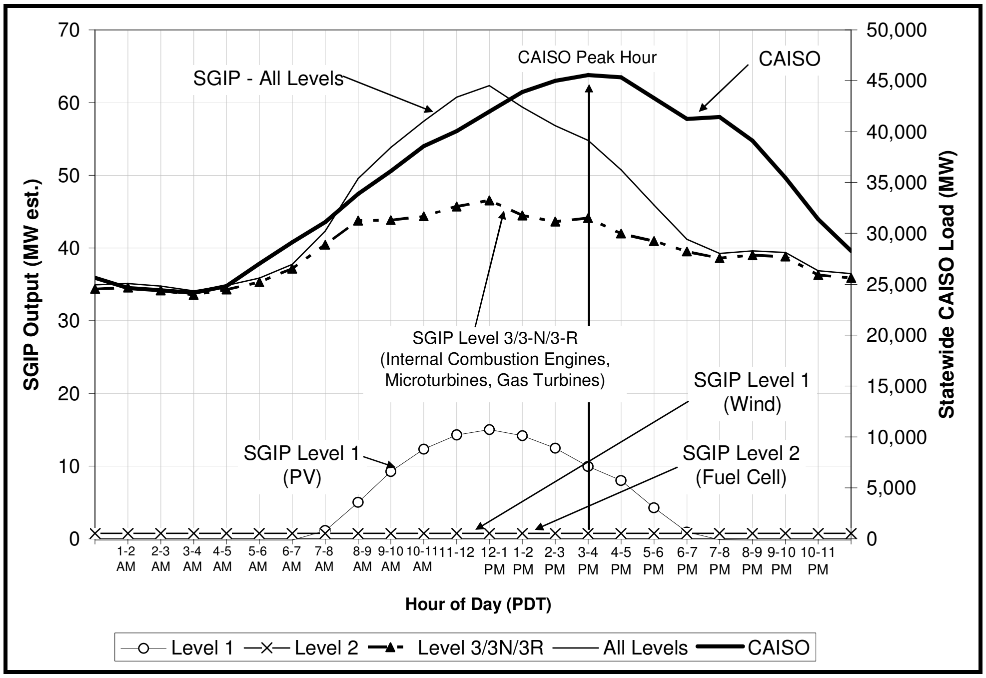
Additional information concerning the SGIP demand impact on the day of the 2004 CAISO system peak is presented in Figure 1-1. The hourly profiles of CAISO system load are presented alongside those of aggregated SGIP project electric power output to summarize the relative magnitudes contributed by each SGIP technology, and to summarize the relationship between demand impact and hour of day.

While PV system power output was substantial on the day of the CAISO system peak, the PV output curve shape is more pointed than the CAISO load shape. After 1 p.m., the total output of the 235 on-line PV systems began falling, whereas CAISO loads continued to increase for several hours. The shape of the output curve estimated for the 150 on-line engines and turbines aligns well with the statewide CAISO system peak from 3 p.m. to 4 p.m., and the two curves maintain a similar relationship during both diurnal shoulder periods (before and after the peak hour).

On the day of the 2004 CAISO system peak the maximum power output of engines, microturbines, and gas turbines exceeded the maximum power output of PV systems by a factor of approximately three. However, the weighted average contribution to demand impacts of both these Level 3 technologies and Level 1 PV during the hour of the CAISO system peak may be lower than expected (i.e., 0.58 kW per 1.00 kW of system capacity based on rebated size for engines, microturbines, and gas turbines, and 0.39 kW per 1.00 kW of system capacity based on rebated size for PV). While one wind turbine and two fuel cells were on-line, these small numbers preclude drawing general conclusions for them regarding technology-specific generation profiles on system peak days.

During hours when CAISO system loads reach maximum values there was substantial variability in engine/microturbine output (including substantial portions that were not operating). The power output of PV systems exhibited less variability, and to a great extent can be explained by known factors influencing actual PV system power output, as compared to their rated system sizes used for establishing the incentive.

Figure 1-1: CAISO 2004 Peak Day Loads & Estimated Total SGIP Generation



1.3 Energy Impact

Overall program electrical energy impacts are summarized in Table 1-2. Interpretation and use of absolute measures of program electric energy impacts (i.e., MWh) is complicated by the fact that additional systems are regularly coming on-line. The weighted-average capacity factors provide more general information regarding the energy production characteristics of SGIP projects.

Table 1-2: Program Electric Energy Impact in 2004

Level / Basis	Total Generation (MWh)	Weighted-Average Capacity Factor (%)
Level 1 / PV	33,835	16%
Level 1 / Wind	339	22%
Level 2 /Fuel Cell	4,286	91%
Level 3/3-N/3-R ICE/Turbine	286,193	45%
Total	**324,653**	**38%**

System Efficiencies

Level 2 fuel cells and Level 3/3-N engines/turbines are subject to certain heat recovery and system efficiency requirements during the implementation stage of the SGIP. The end-uses served by recovered useful thermal energy include heating, cooling or both. Available metered thermal data and input fuel collected from on-line cogeneration projects were used to calculate overall system efficiency incorporating both electricity produced as well as useful heat recovered. Results of the analysis for Level 3/3-N projects are summarized in Table 1-3.

Table 1-3: Level 3/3-N Cogeneration System Efficiency (n=31)

Summary Statistic	218.5 (b) Efficiency	Overall Plant Efficiency
Range	19% - 54%	22% - 82%
Median	36%	46%
Mean	37%	49%

Metered data collected to date suggest that nine of the 31 monitored Level 3/3-N projects achieved the 218.5 (b) overall system efficiency target of 42.5%. The limited quantities of cogeneration system data available for the present impact analysis suggest the possibility of systematic negative variance between planned system efficiencies and actual system efficiencies. Actual electrical conversion efficiencies and heat recovery rates both play important roles in explaining the variance. However, collection and analysis of additional data is required before definitive conclusions can be drawn.

1.4 SGIP Participant Perspectives

The following are the key findings summarized from the results of interviews with 45 SGIP PV system owners and 47 SGIP cogeneration system owners based upon their system implementation and operations experienced during 2004.

PV Systems

- The most common reason for installing a PV system was to offset the utility bill. The second most common reason given was to help the environment.
- The results of these interviews reveal that system owners are, on average, very satisfied with their SGIP systems. Most, given the need, would install another system, and many reported they are in the process of doing that.
- A majority (67%) of PV system owners interviewed reported that they clean their solar panels. The frequency of cleaning ranged from twice a week to once a year.

Cogeneration Systems

- Although energy production to date has been below planned levels, respondents were optimistic that actions taken, especially actions to improve maintenance would increase future capacity utilization and reliability.
- There was considerable concern about the high cost and volatility of natural gas markets.
- Heat utilization equipment malfunction was frequently mentioned as a factor in both decreased waste heat utilization and overall poor performance of the cogeneration system.

1.5 Implication of Findings

In assigning implications to the above findings of this impacts assessment, although the system electric generation data were generally rich, it must be noted in many cases that the quantity of useful thermal energy data available for this analysis is small. For some of these projects much less than a complete year of data were available, and data analysis efforts were complicated by the fact that additional evaluated projects continued to come on-line throughout the year.

Taking the above caveat into consideration, overall, while the SGIP is very well-subscribed and program participants are on average satisfied with their SGIP systems, it appears that many of the Level 3/3-N cogeneration systems are not performing as well or operating as many hours as originally expected. The weighted average annual capacity factor of these cogeneration systems was 45% during 2004 and during hours when CAISO loads reached their peak a surprisingly large proportion of the engines and turbine generators were not operating.

Dissemination of this impact evaluation's findings could contribute to better performance for cogeneration systems installed in the future. If prospective SGIP participants are aware of challenges faced by current participants then they may be better able to make decisions concerning system design and specification that will yield improved performance. This is true for the system vendors as well as for system owners because as the distributed generation market grows there will be new market entrants on the vendor side as well as on the customer side. Currently plans are in place to develop brochures summarizing key information contained in this and other program evaluation reports. These materials will be made available on the Web sites of the SGIP's Program Administrators. Other means of outreach, including public workshops and presentations to key stakeholders, will also contribute to further dissemination of these SGIP evaluation findings.

2

Introduction

2.1 Background

In response to Assembly Bill 970, which required the California Public Utilities Commission (CPUC) to initiate certain load control and distributed generation program activities, the CPUC issued Decision 01-03-073 (D.01-03-073) on March 27, 2001. This Decision mandated implementation across the service territories of California's investor-owned utilities (IOUs) of a self-generation program designed to produce significant public (e.g., environmental and energy distribution system) benefits for all ratepayers, including gas ratepayers. To meet this mandate, the California Self-Generation Incentive Program (SGIP) was created to offer financial incentives to customers of IOUs who install certain types of distributed generation (DG) facilities to meet all or a portion of their energy needs. The SGIP has been operational since July 2001. This report provides the findings of an impact evaluation addressing the fourth year of this program, during the calendar year 2004.

The report documents the evaluation approach, monitoring plan procedures, data collection, and analysis results. It is one of a series of SGIP impact evaluation reports, which assess energy production and system peak demand reductions for successive calendar years, as summarized in Table 2-1 below.

Table 2-1: SGIP Impact Evaluation Reports Prepared to Date

Calendar Year Covered	Date of Report
2002[1]	April 17, 2003
2003[2]	October 29, 2004
2004	April 15, 2005

These annual program impact evaluations represent a critical component of an overall program evaluation plan that also involves program process evaluations and program cost-

[1] California Self-Generation Incentives Program – Second-Year Impacts Evaluation Report, Submitted to Southern California Edison, Prepared by Itron, Inc., April 17, 2003.

[2] CPUC Self-Generation Incentive Program – Third-Year Impacts Assessment Report, Submitted to The Self-Generation Incentive Program Working Group, Prepared by Itron, Inc., October 29, 2004.

effectiveness evaluations. A preliminary program cost-effectiveness evaluation report covering program years 2001-2004 (PY01-PY04)[3] is scheduled to be completed by late spring 2005. The data and analysis underlying the annual impact evaluation reports, which includes electric, fuel, and thermal energy data, will contribute to development of key inputs to the cost-effectiveness evaluation.

This introductory section provides a brief description of the SGIP, an overview of the DG market in California, a summary of prior annual impact evaluation objectives and key results, an outline of the objectives of the calendar year 2004 impact evaluation, and a summary of the organization of the remainder of the report.

2.2 Program Description Update

The SGIP provides financial incentives for the installation of certain electric generation equipment on the customer side of the utility meter that meet all or a portion of the electric needs of an eligible customer's facility. Several key parties direct the SGIP design and implementation. Under the direction of the California legislature and CPUC, the SGIP is administered on a regional joint-delivery basis through three IOUs—Southern California Edison (SCE), Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCalGas)—and one non-utility Program Administrator, the San Diego Regional Energy Office (SDREO).[4] A high-level overview of the critical SGIP milestones associated with these parties is presented in Table 2-2 on the following page.

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[3] "Program Year" refers to the period in which an applicant is accepted into the program. "Calendar Year" simply refers to a specific 12-month period.

[4] SDREO is the program administrator for San Diego Gas & Electric customers.

Table 2-2: Major SGIP Milestones by Key Party

Calendar Year	SGIP Party: Legislature	SGIP Party: CPUC	SGIP Party: Program Administrators/Applicants
2000	Legislation underlying SGIP (AB970) is enacted		
2001		Order underlying SGIP issued (D.01-03-073)	First SGIP application received (July 2001)
2002		Order splitting Level 3 into Level 3-N/3-R[5] issued (D.02-09-051)	1st SGIP incentives awarded for completed projects
2003	Legislation extending SGIP passes (AB1685)		On-line SGIP capacity exceeds 50 MW
2004		Order modifying SGIP issued (D.04-12-045)	1st SGIP wind project on-line
2007			Currently scheduled deadline for SGIP project completion (December 31, 2007)

DG technologies eligible for SGIP support are presented in Table 2-3, which summarizes key design elements governing SGIP projects coming on-line prior to the end of 2004. For each of these incentive levels and eligible technologies the SGIP incentive is limited to the first 1,000 kW of system capacity.[6] For the remainder of this report, microturbines and small gas turbines are collectively referred to as "turbines" in certain cases, while internal combustion engines (ICE) are simply referred to as "engines."

5 This division separates non-renewable (N) and renewable (R) fuel.

6 CPUC Rulings have increased the eligible maximum system size beyond 1,000 kW – although the maximum incentives basis remains capped at 1,000 kW.

Table 2-3: Summary of SGIP Design for Projects On-Line as of 12/31/2004

Program Incentive Category	Maximum Incentive Offered ($/watt)	Maximum Incentive as a % of Eligible Project Cost	Minimum System Size (kW)	Eligible Generation Technologies
Level 1	$4.50	50%	30	■ Photovoltaics (PV) ■ Fuel Cells[1] ■ Wind Turbines
Level 2	$2.50	40%	None	■ Fuel Cells[2,3]
Level 3	$1.00	30%	None	■ Microturbines[1,2,,3,4] ■ Internal combustion engines and small gas turbines[1,2,3,4]
Level 3-R	$1.50	40%	None	■ Microturbines[1] ■ Internal combustion engines and small gas turbines[1]
Level 3-N	$1.00	30%	None	■ Microturbines[2,3,4] ■ Internal combustion engines and small gas turbines[2,3,4]

1. Operating on renewable fuel
2. Operating on non-renewable fuel
3.Using sufficient waste heat recovery
4. Meeting reliability criteria

As suggested by the timeline presented in Table 2-2, the SGIP has evolved through time. Its term and eligibility criteria have been modified, new incentive levels have been created (i.e., Levels 3-R and 3-N), and other incentive levels have been retired (i.e., Level 3). The variety of SGIP terms and conditions affecting on-line projects will continue to increase in the future. For example, beginning January 1, 2005, combustion-based projects using non-renewable or fossil fuels will be required to satisfy certain new air pollutant emissions requirements stipulated in Assembly Bill 1685.[7]

The SGIP is designed to complement the California Energy Commission's (CEC's) existing Emerging Renewables Program. This is accomplished primarily by the SGIP's focus on non-residential market sectors, including commercial, industrial, and agricultural. The 30 kW Level 1 minimum system size is an important factor contributing to achievement of this focus. Most residential customers do not have the on-site electrical load or space availability to support installation of a PV or wind turbine system as large as 30 kW. Coordination with

[7] For additional detailed information regarding SGIP program design governing projects entering the SGIP in 2005 and later years, the relevant legislation, orders, decisions, and SGIP Handbook updates are the best source of information.

the CEC Emerging Renewables Program occurs through several administrative processes, including participation in the Statewide SGIP Working Group and through a separately managed statewide SGIP compliance database.

2.3 California Market for Distributed Generation

The California market for DG is complex and dynamic. Numerous stakeholders are working to manage its development in ways that strike a satisfactory balance between such factors as reliability, cost effectiveness, and environmental impact. At the center of this mix is the SGIP, which has accelerated the rate of adoption of DG technologies in California.

The SGIP third-year impact evaluation report includes a general overview of key factors affecting this market. Based largely on content from the CEC's Web site, this overview describes background factors underlying the market for DG, including market participants, market status, and market niches. Both the evaluation report and the CEC's Web site remain valuable sources for general background information framing SGIP market activity.

In the course of conducting this fourth-year impact evaluation study, a number of specific factors affecting the market for DG in California were identified. Discussed briefly below, these include global factors, national factors, state factors, technology evolution, and centralized generation.

Global Factors: The tight global market for PV modules has affected the availability and the price of hardware in the California market. A source of data on global PV markets suggests that "…end-customer prices [will] remain firm (0 to 5 percent annual increase) until the entire sector reaches overcapacity in 2007 through 2008."[8] In addition, high global prices for oil and natural gas have recently kept upward pressure on electric energy production and natural gas fuel costs and their associated market prices in the western United States.

National Factors: California's market for DG is affected by broader economic factors including fossil fuel energy prices, economic growth rates and interest rates. Federal and state tax policies have also influenced the California market. At the Federal level, a permanent 10% tax credit is available for PV systems. Both PV and non-PV systems installed from 2003 through 2004 may have been eligible for the 30% Federal Stimulus depreciation tax benefit under the Economic Recovery Act of 2001. For customers with certain tax circumstances, these programs can reduce DG total costs, thereby encouraging its adoptions.

[8] Michael Rogol and Shintaro Doi, "When will the good times end?" *PHOTON International*, January 2005, p. 36.

State Factors: The most influential state factor is the SGIP itself. Financial support provided by the program has substantially increased the deployment rate of DG. The response to the SGIP for PV incentives has reached levels resulting in lengthy wait lists of projects for which funding may not become available due to limited program resources. These existing wait lists may contribute to future market uncertainty. A State tax credit is available for SGIP participants purchasing PV systems from 2001 through 2005. The tax credit was 15% during 2001 through 2003. It is currently 7.5% and is scheduled to expire on January 1, 2006.

Technology Evolution: Recent examples of technology evolution include the departure of major manufacturers from the thin film PV market, entry of new PV inverter manufacturers into the DG market, introduction of new heat recovery *adsorption* chiller technology, and introduction of new generations of microturbine technology. Technologies utilized for certain combustion systems have been evolving to satisfy new air pollutant emissions constraints affecting engine eligibility for the SGIP beginning in 2005.

Centralized Generation: Processes for bringing more conventional sources of electric power on-line continue to evolve. Events and developments affecting the cost and availability of electricity from more conventional sources, including transmission and central-station generation, also affect California's DG market. For example, in recent years, uncertainty related to the state's power procurement process may have contributed to construction delays for power plants that had already made it through the permitting process. All else equal, delays in bringing new centralized generation capacity on-line may increase the benefits of new DG capacity.

2.4 Objectives and Key Results of Previous SGIP Impact Evaluations

At the most fundamental level, the objectives of all of the annual SGIP impact evaluation analyses are identical. Principal among them is to produce information that will better enable the program's many stakeholders to make informed decisions to optimize the SGIP's implementation and design. Strategies employed to achieve these objectives include:

- Compile and summarize electrical energy production and power output by specific time-periods and technology-specific factors,
- Determine operating and reliability statistics,
- Determine compliance with the program's thermal energy utilization and system efficiency requirements,
- Determine compliance of Incentive Level 1 fuel cell systems and Level 3-R engine/turbine systems with the renewable fuel usage requirements, and

- Review available renewable fuel clean-up equipment costs for Level 1 fuel cells and Level 3-R systems (second-year impact evaluation report only).

Previous SGIP impact evaluation reports provide important background information and additional context for the 2004 program results. The report of third-year impacts dated October 29, 2004, is worthy of special note, as it contains detailed discussions of important evaluation topics, including: definition of hypothetical baselines, distinction between gross generator output and net generator output, and specification of process points upon which to base thermal energy recovery estimates.

Demand impacts of the SGIP estimated for 2002 and 2003 are summarized in Table 2-4. The basis of these demand impacts is power output of SGIP projects coincident with the annual maximum hourly load of the electrical system managed by the California Independent System Operator (CAISO)[9].

Table 2-4: Demand Impact Coincident with 2002 & 2003 CAISO System Peak Load

	2002			2003		
Incentive Level	**On-Line Systems (n)**	**On-Line Capacity (kW)**	**Peak Demand Impact (kWp)**	**On-Line Systems (n)**	**On-Line Capacity (kW)**	**Peak Demand Impact (kWp)**
1: PV	11	1,130	790	105	12,671	7,494
2: Fuel Cell	2	400	400	1	200	187
3/3-N/3-R: Engine/Turbine	17	6,752	5,472	89	46,010	27,410
Total Program	**30**	**8,282**	**6,662**	**195**	**58,881**	**35,091**

A key result of the peak electric demand impact analysis is the rate at which on-line DG system capacity yields peak demand impact on the electric system. For 2003, the rates were similar for PV (0.59 kWp/kW) and engines/turbines (0.60 kWp/kW). While these results are of similar magnitude, the factors underlying them are very different. An on/off switch does not control PV system output, and PV systems are typically allowed to export excess power to the grid under the constraints of net-metering agreements. However, PV system power output is affected by weather, local environment, PV module orientation, PV system design, and PV system maintenance. Effects of these factors are discussed in more detail in

[9] The California Independent System Operator is a not-for-profit corporation that on March 31, 1998, assumed management of the long-distance, high-voltage power lines that deliver electricity throughout 75% of California. The 2002 CAISO system peak load of 42,352 MW was experienced on Wednesday, July 10, 2002 during the hour from 2:00 to 3:00 p.m. (PDT). The 2003 CAISO system peak load of 42,581 MW occurred on Monday, July 21, 2003, during the hour from 3:00 to 4:00 p.m. (PDT).

Appendix B of this report, *PV Performance Details*. Engine/turbine system power output, on the other hand, is controlled by an on/off switch or a load-following control system, and is influenced by fuel prices relative to electric prices, and these natural gas fueled systems typically are not allowed to export power to the grid. Additionally, engine/turbine systems comprise rotating machinery operating at high speeds and high temperatures. As such, they are subject to different maintenance, operation, and reliability issues than are PV systems.

Overall SGIP electrical energy impacts estimated for 2002 and 2003 are presented in Table 2-5. While Level 3/3-N/3-R engines and turbines accounted for 78% of 2003 peak demand impact, they accounted for 91% of total 2003 energy impact. This difference is due to the fact that the average system capacity factor (a ratio indicating hours of full-load operation to total available operating hours over a stated period of time) of Level 3/3-N/3-R engines and turbines is greater than that for Level 1 PV systems.

Table 2-5: Annual Energy Impact Estimated for 2002 & 2003 (MWh)

Incentive Level	2002	2003	Total
1: PV	1,848	15,402	17,250
2: Fuel Cell	2,617	1,635	4,252
3/3-N/3-R: Engine/Turbine	27,677	166,583	194,260
Total Program	**32,143**	**183,620**	**215,763**

Operating efficiency of SGIP cogeneration systems is also a focus of annual impact evaluations. Level 2 fuel cell and Level 3/3-N engine/turbine cogeneration system designs are required to demonstrate (on paper through engineering design documentation) achievement of certain minimum overall system efficiencies, including a PUC 218.5(b) system efficiency target of 42.5%. This measure of overall system efficiency credits recovered useful heat at a rate of 50% of its actual value within the system efficiency equation. For 2003, PUC 218.5(b) efficiencies were estimated for 20 monitored Level 3/3-N systems using available metered data. Of these 20 systems, two achieved the 218.5(b) overall system efficiency target of 42.5%.

This considerable discrepancy between and planned and actual system efficiencies should be considered carefully due to the limited quantities of cogeneration system data that were available for the 2003 impact analysis. Available electric, fuel, and heat data indicate that this variance is due to at least two factors. First, actual gross electrical conversion efficiencies were consistently lower than those assumed for project design purposes. Second, actual heat recovery rates were lower than those assumed for project design purposes. It is important to caution that these initial findings for a small sample of projects may not accurately represent system efficiency performance at the SGIP level as a whole.

2.5 Fourth-Year Impact Evaluation Objectives

The majority of evaluation approaches and procedures underlying the 2004 impact evaluation are unchanged from those employed for the third-year (2003) impact evaluation. The focus of the present report is on those areas where approaches, procedures, and impact results varied from those reported for the third year of the program.

Fundamental objectives of the fourth-year impact evaluation are identical to those of analyses completed for previous years. However, the analysis was enhanced in several ways. Areas of enhancement include:

- Assessment of the impact of SGIP projects on municipal electric distribution systems versus electric distribution systems of the IOUs,
- Assessment of performance trends for individual projects through time,
- Assessment of perspectives of risk-bearing SGIP participants, and
- Preliminary assessment of the influence of PV module washing on PV system performance.

Data from numerous sources contributed to the analysis. These data sources include:

- Statewide program tracking database compiled from the four Program Administrators' tracking databases,
- IOU and energy service provider electric metering data of net generator electric output, and
- Other required operational data (e.g., recovered thermal energy, natural gas consumption for Level 2 & 3/3-N/3-R cogeneration projects) collected under the program metering, data collection, and site verification tasks.

2.6 Report Organization

An executive summary, which provides a high-level overview of the key objectives and findings of this fourth-year impact evaluation, is presented in Section 1 of this report. The remainder of the report is organized as described below.

- **Section 3** presents the evaluation work plan update, which addresses the revisions for the fourth-year program evaluation work scope and the schedule for the 2004 and 2005 evaluation activity.
- **Section 4** presents a summary of the program status and characterization of participants entering the SGIP through the end of 2004.
- **Section 5** discusses the fourth-year and future impact evaluation sample design issues.

- **Section 6** addresses the data collection activities for this assessment.
- **Section 7** discusses the system monitoring and operational data collection efforts.
- **Section 8** addresses the program impact assessment analytic methodology and results, as well as certain performance characteristics of operational projects.
- **Section 9** explores the perspectives of risk-bearing program participants (system owners).
- **Section 10** presents evaluation summary results and key findings.
- **Appendix A** contains additional detail regarding the performance of PV systems.
- **Appendix B** contains the guides for the System Owner Interviews.
- **Appendix C** contains selected comments from the System Owner Interviews.

3

Measurement & Evaluation Work Plan Update

This section provides a brief discussion of the progression of the SGIP's measurement and evaluation (M&E) work plan and its current status as of the end of the first quarter of 2005. An overview of the current M&E work plan is discussed in Section 3.1, recent updates are addressed in Section 3.2, and the fourth-year evaluation tasks are described in Section 3.3. This M&E work plan update does not address the 2005 program revisions or the metering and data collection associated with future projects resulting from the recent Assembly Bill 1685 program extension.

3.1 Background and Overview of M&E Work Plan

The M&E work plan prepared for this program evaluation effort was derived from a series of tasks defined by the SGIP Working Group and its evaluation Project Manager. Initial SGIP M&E support activities included the following:

- Develop the program evaluation scope,
- Provide statistical methods assessment and system sampling,
- Develop program participant characterization,
- Compile and summarize CPUC and other program participation,
- Determine system operational characteristics,
- Implement on-site monitoring, data collection, and field verification inspections,
- Develop program recommendations to improve on-peak load impacts,
- Provide Program Administrator comparative assessment (utility vs. non-utility),
- Prepare annual program evaluation reports, and
- Prepare other evaluation project deliverables.

Goals were also established by the SGIP Working Group for this program evaluation effort. In addition to the goal of developing the M&E work plan itself, other initial M&E goals included:

- Develop and implement a performance data collection system and reporting framework,

- Perform annual process and impact evaluations, as required, reporting SGIP impact, and
- Develop recommendations regarding potential improvements to the SGIP.

This early M&E planning work, which was coordinated with the SGIP Working Group, along with the first-year clarifications led to the M&E work plan incorporated as Section 2 of the First-Year Process Evaluation Report. During 2002 and 2003, the plan was revised to reflect a number of changes in the program required by the CPUC. On December 16, 2004, the SGIP was formally extended by CPUC Decision 04-12-045 for a period of three years, accepting applications subject to funding availability through the end of 2007. These various revisions and clarifications, and their overall impacts on the SGIP M&E work plan, are discussed in further detail in Section 3.2 below.

Program Evaluation Criteria

The SGIP was developed to fulfill the requirements of Attachment 1 of CPUC Decision 01-03-073 (Adopted Programs to Fulfill AB 970 Load Control and Distributed Generation Requirements, March 27, 2001). The original Decision stated the program's objectives, as listed in the "Goals/ Rationale/Objectives" column in Table 3-1 below. With input from the SGIP Working Group, the program evaluation contractor (Itron, Inc.) developed criteria for assessing achievement of each goal. These criteria are listed in the "Criteria for Meeting Program Goal" column in Table 3-1. The Administrative Law Judge (ALJ) Gottstein Ruling of April 24, 2002, approved these criteria and the schedule of SGIP M&E reports through April 2005. This fourth-year impact evaluation report may be used to assess progress on meeting criteria C1.B, C1.C, and C3.B. [1]

[1] For a discussion and evaluation of remaining criteria, see: Self-Generation Incentive Program Second Year Process Evaluation, April 25, 2003.

Table 3-1: Evaluation Criteria of the Self-Generation Incentive Program

Goal/Rationale/Objective	CR #	Criteria for Meeting Program Goal
G1 Encourage the deployment of distributed generation in California to reduce peak electrical demand	**C1.A**	Increased customer awareness of available distributed generation technology and incentive programs
	C1.B	Fully subscribed participation in program (i.e., total installed capacity, number of participants)
	C1.C	Participants' demand for grid power during peak demand periods is reduced
G2. Give preference to new (incremental) renewable energy capacity	**C2.A**	Development and provision of substantially greater incentive levels (both in terms of $ per watt and maximum percentage of system cost)
	C2.B	Provision of fully adequate lead-times for key program milestones (i.e., 90 day and 12 month)
G3 Ensure deployment of clean self-generation technologies having low and zero operational emissions	**C3.A**	Maximum allocation of combined budget allocations for Level 1 and Level 2 technologies
	C3.B	A high percentage of Level 1 and Level 2 projects are successfully installed with sufficient performance
G4 Use an existing network of service providers and customers to provide access to self-generation technologies quickly	**C4.A**	Demonstration of customer delivery channels for program participation to include distributed generation service providers and existing utility commercial/industrial customers networks
G5 Provide access at subsidized costs that reflect the value to the electricity system as a whole, and not just to individual customers	**C5.A**	Demonstrate that the combined incentive level subscription, on an overall statewide program basis (i.e., the participant mix of Levels 1, 2, and 3 across service areas), provides an inherent generation value to the electricity system (avoided generation, capacity, and T&D support benefits).
G6 Help support continued market development of the energy services industry	**C6.A**	Quantifiable program impact on market development needs of the energy services industry
	C6.B	Demonstrated consumer education and program marketing support as needed
	C6.C	Tracking of energy services industry market activity and participation in the program
G7 Provide access through existing infrastructure, administered by the entities (i.e., utilities and SDREO) with direct connections to, and the trust of small consumers	**C7.A**	Ensure that program delivery channels include communications, marketing, and administration of the program, providing outreach support to small consumers
G8 Take advantage of customers' heightened awareness of electricity reliability and cost	**C8.A**	Use existing consumer awareness and interact with other consumer education/marketing support related to past energy issues to market the program benefits.

3.2 Revisions to the M&E Work Plan

During the first three and one-half years of the program, a number of modifications and regulatory oversight clarifications have been formalized through a series of CPUC Decisions, Interim Orders, and ALJ Rulings. These include the following formal actions, which have impacted the SGIP or its evaluation plans, as follows:

- Adoption of Decision 02-02-026 dated February 7, 2002 (Interim Order),
- ALJ Gottstein Ruling dated April 24, 2002 (On Evaluation Criteria, Plan and Schedule of M&E Reporting Activity),
- Adoption of Decision 02-09-051 dated September 19, 2002 (Interim Opinion addressing the eligibility of Renewable Fueled Microturbines for SGIP Incentives),
- Adoption of Decision 03-04-030 dated April 3, 2003 (Opinion on Cost Responsibility Surcharge Mechanism for Customer Generation Departing Load),
- ALJ Gottstein Ruling dated December 10, 2003 (Requesting Comments on AB 970 Self Generation Incentive Program Evaluation Reports and Related Issues), and
- Adoption of Decision 04-12-045 dated December 16, 2004 (Order to Modify the Self-Generation Incentive Program and Implement AB 1685).

In addition to these CPUC actions, in March 2003, three of the Program Administrators (PG&E, SCE and SoCalGas) requested proposals from and executed purchase orders with the program evaluation contractor to provide electric net generator output (ENGO) metering of a portion of their operational SGIP systems. These monitored systems included either: 1) the net-metered Level 1 projects, or 2) all of the Program Administrator's Level 1, 2 and 3 SGIP projects determined to require independent ENGO metering. These ENGO metering installations are being performed outside of the Statewide Program Administrator evaluation contract. They are being implemented directly with the individual Program Administrators.

As a result of the above-listed actions by the CPUC, a two-year work plan addendum was developed that addressed the required (and several optional) M&E tasks relevant from PY03 through the date of this fourth-year impact evaluation report. These additional work activities include:

- Procurement and installation of all thermal energy and biogas monitoring systems for sampled PY02-PY04 participants, including natural gas meters where required,
- Removal of one-half of the thermal energy meters, natural gas meters and biogas monitoring systems upon completion of required M&E,
- Development of SGIP Impact Reports for 2003 and 2004,
- Completion of an optional process evaluation during 2004, and
- Provision of the added renewable fuel use/cost monitoring and reporting per D.02-09-051.

In late 2004, the M&E work plan was again updated to address a number of required revisions to the work scope optional tasks and a term extension for the purposes of continuing metering and data collection for projects operational in 2004. Additional M&E work activities include the following:

- Refinement of the optional targeted process evaluation work scope (Task 13.A),
- Inclusion of the SGIP cost-effectiveness evaluation framework's development and initial cost-effectiveness evaluation implementation (Task 13.B) during the first half of 2005, and
- Continuation of monitoring and data collection activities (Tasks 11 and 12) for on-line projects through December 31, 2005.

The following list summarizes the M&E work activities scheduled to be performed from January 2004 through December 2005 as a result of these updates.

- Monitoring plan development and implementation of thermal energy monitoring systems,
- Perform annual program impact evaluation (including metered data verification, operational data collection and management, coordination and analysis),
- Perform targeted process evaluation,
- Provide preliminary cost effectiveness assessment,
- Refine existing M&E work plan (on-going),
- Prepare and submit other M&E deliverables (on-going), and
- Prepare and submit additional M&E reports as directed by the CPUC (through December 2005).

Table 3-2 contains the revised SGIP M&E estimated budgets including the original contract and the incremental work plan activity over the PY03 through PY04 period, including each Program Administrator's estimated share of the M&E budget. These Administrator-specific budget allocation factors are based on the proportion of overall program budgets that were allocated by the CPUC under D. 01-03-073. In addition, co-funded M&E expenditures through December 31, 2004, are identified for the original work plan and the amended M&E contract scope.

Table 3-2: Measurement and Evaluation Four-Year (2002-2005) Program Estimated Budget

Allocation Factors	**48.0%**	**26.0%**	**13.6%**	**12.4%**	**100.0%**	
	PG&E Share	**SCE Share**	**SoCalGas Share**	**SDREO Share**	**Total M&E Budget**	**Expenditures to Date (12/31/04)**
Original Contract	$878,026	$475,597	$248,774	$226,823	$1,829,220	$1,789,600
Incremental	$1,534,394	$831,131	$434,745	$396,385	$3,196,655	$1,333,337
Total Program	$2,412,420	$1,306,728	$683,519	$623,208	**$5,025,875**	**$3,122,937**

3.3 Schedule for Fourth-Year Evaluation Tasks

The SGIP evaluation activity schedule for the period 2002 through 2005 is summarized in Table 3-3. The fourth-year evaluation reports now include: 1) Onsite Monitoring Fuel-use Report No. 5, 2) Fourth-Year Program Impact Evaluation Report and 3) Preliminary Program Cost-Effectiveness Evaluation Report.

Table 3-3: Summary of SGIP M&E Deliverables

M&E Report	Due Date	Compliance
First-Year Incentives / Program Design Evaluation / Recommendations Report	June 28, 2002	Submitted in lieu of First-Year Peak Operations Impacts; recommendations for Program Year 2002
Outline for Second-Year Program Impact Evaluation Report	December 18, 2002	Per ALJ Gottstein 4/24/02 Ruling
Outline for Second-Year Program Process Evaluation Report	December 25, 2003	Per ALJ Gottstein 4/24/02 Ruling
Onsite Monitoring Fuel-use Report #1	March 17, 2003	Renewable fuel use monitoring and cost comparison of Level 3 and 3-R Projects

M&E Report	Due Date	Compliance
Outline for Utility / Non-Utility Administrator Comparison Report	April 3, 2003	Per ALJ Gottstein 4/24/02 Ruling
Second-Year Program Impact Evaluation Report	April 18, 2003	Assess energy production and system peak demand reductions occurring during PY02
Second-Year Program Process Evaluation Report	April 25, 2003	Provide recommendations on incentives or program designs that could improve peak load reduction for PY03
Utility / Non-Utility Administrator Comparison Report	August 1, 2003	Provide an analysis of the relative effectiveness of the utility and non-utility administrative approaches during program years 2001 & 2002
Onsite Monitoring Fuel-use Report #2	September 17, 2003	Renewable fuel use monitoring and cost comparison of Level 3 and 3-R Projects.
Outline for Third-Year Program Impact Evaluation Report	December 16, 2003	Per ALJ Gottstein 4/24/02 Ruling
Onsite Monitoring Fuel-use Report #3	March 17, 2004	Renewable fuel use monitoring and cost comparison of Level 3 and 3-R Projects.
Onsite Monitoring Fuel-use Report #4	September 17, 2004	Renewable fuel use monitoring and cost comparison of Level 3 and 3-R Projects.
Third-Year Program Impact Evaluation Report	October 18, 2004	Assess energy production and system peak demand reduction impacts occurring during PY03
Program Cost-Effectiveness Framework	February 2005	Address (partial) requirement in ALJ Ruling for Energy Division to develop cost-effectiveness assessment of all Load Removal Programs
PY04 Targeted Process Evaluation Report	December 15, 2004	Assess specific Program implementation and evaluation issues at the Request of the SGIP Working Group
Outline for Fourth-Year Program Impact Evaluation Report	December 15, 2004	Per ALJ Gottstein 4/24/02 Ruling
Onsite Monitoring Fuel-use Report #5	March 17, 2005	Renewable fuel use monitoring and cost comparison of Level 3 and 3-R Projects.
Fourth-Year Program Impact Evaluation Report	April 15, 2005	Assess energy production and system peak demand reductions occurring during PY04
Preliminary Cost-Effectiveness Assessment	(TBD) expected by May 31, 2005	Per Decision 04-12-045 dated December 16, 2004 (Order to Modify the Self-Generation Incentive Program and Implement AB 1685)
Subject to funding availability Program Incentives End for eligible Applications received by	January 1, 2008	Per Decision 04-12-045 dated December 16, 2004

Note: Process and Impact Evaluation Reports cover January 1 - December 31 of specified year. The first Program Year is 2001.

4

Program Status Overview

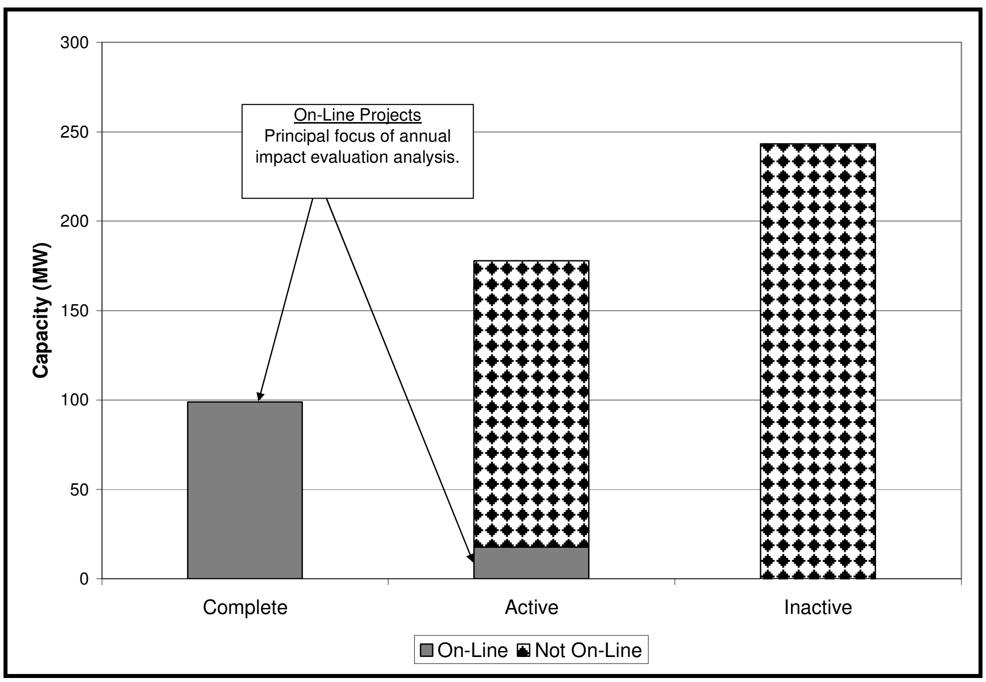
4.1 Introduction

This section provides a summary of participant characteristics statewide for all applicants to the PY01-PY04 SGIP, based on Program Administrator tracking data available through December 31, 2004. Characteristics summarized in this section include on-line status, system capacity, incentive paid or reserved, and project cost. First, an overview summarizes program participation according to on-line status and incentive payment status. Following this, characteristics of completed and active projects are discussed. Finally, a description of inactive projects is provided.

4.2 Overview

The status of SGIP projects is summarized at a very high level in Figure 4-1.

Figure 4-1: Summary of PY01-PY04 SGIP Project Status as of 12/31/2004



This graphic illustrates project status by stage in the SGIP implementation process and on-line status. "On-line" projects are defined as those that have entered normal operations.[1] Key stages in the SGIP implementation process include:

- ***Complete Projects:*** System has been installed and inspected through an on-site verification and an incentive check has been issued. All of these projects are considered "on-line" for impact evaluation purposes.
- ***Active Projects:*** Projects that have not been withdrawn, rejected, completed, or placed on a wait list.[2] As time goes on the active projects will migrate either to the Complete or to the Inactive category. Some, but not most, of these projects had entered normal operations as of the end of 2004, but were not considered Complete, as an incentive check had not yet been issued.
- ***Inactive Projects:*** Projects that have been withdrawn or rejected, and are no longer progressing in the SGIP implementation process.

Table 4-1 provides a breakdown by incentive level of the high-level summary of Complete and Active projects depicted graphically in Figure 4-1.

Table 4-1: Quantity and Capacity of Complete & Active Projects

Incentive Level	Technology	Complete (n)	Complete (MW)	Active (All) (n)	Active (All) (MW)	Total (n)	Total (MW)	Total Avg Size (kW)
1	Photovoltaic	269	29.6	498	75.1	767	104.7	137
	Wind Turbine	0	0.0	5	3.3	5	3.3	664
	Fuel Cell	0	0.0	2	0.8	2	0.8	375
2	Fuel Cell	2	0.8	5	2.7	7	3.5	493
3	Engine/Turbine	88	42.2	14	7.1	102	49.3	483
3-N	Engine/Turbine	51	25.4	169	82.0	220	107.4	488
3-R	Engine/Turbine	3	0.8	20	6.9	23	7.7	335
Total	**Total**	**413**	**98.8**	**713**	**177.9**	**1126**	**276.6**	**246**

The Complete and Active projects that were on-line as of December 31, 2004, are the principal focus of the present impact evaluation. These on-line projects represent 116 MW

[1] The reference to having entered 'normal operations' is not an indication that a system is actually running during any given hour of the year. For example, some systems that have entered normal operations do not run on weekends.

[2] Eligible projects are placed on a wait list once funding within the relevant incentive level has been exhausted for that Program Year. Previously, projects that remained on a wait list at the end of the Program Year were required to re-apply for funding for the subsequent funding cycle. This requirement was eliminated in December 2004 by D.04-12-045. Over time some projects will be withdrawn or rejected and replaced by projects from the wait list.

and are summarized by incentive level, technology type, and SGIP implementation stage in Table 4-2 below. They are more fully addressed in later sections of the report that treat sample design, collection of metered data, and impact on electric and fuel usage.

Table 4-2: Quantity and Capacity of Projects On-Line as of 12/31/2004

Incentive Level	Technology	Complete		Active (On-Line)		Total On-Line Projects		
		(n)	(MW)	(n)	(MW)	(n)	(MW)	Avg Size (kW)
1	Photovoltaic	269	29.6	4	1.4	273	31.0	114
	Wind Turbine	0	0.0	1	1.0	1	1.0	950
2	Fuel Cell	2	0.8	0	0.0	2	0.8	400
3	Engine/Turbine	88	42.2	7	5.3	95	47.4	499
3-N	Engine/Turbine	51	25.4	15	9.8	66	35.2	534
3-R	Engine/Turbine	3	0.8	1	0.3	4	1.1	273
Total	**Total**	**413**	**98.8**	**28**	**17.7**	**441**	**116.5**	**264**

Customers of the investor-owned utilities fund the SGIP through the regular cost recovery process administered by the CPUC. Each of these customers is eligible to participate in the SGIP. In some cases these same customers are also customers of municipal utilities. The incidence of these cases is summarized in Table 4-3. Forty-one of the 45 Level 1 PV projects involving a municipal utility customer correspond to SoCalGas SGIP projects. Most of these projects were supported by the SGIP as well as by a solar PV program offered by the municipal utility.

Table 4-3: Electric Utility Type for Projects On-Line as of 12/31/2004

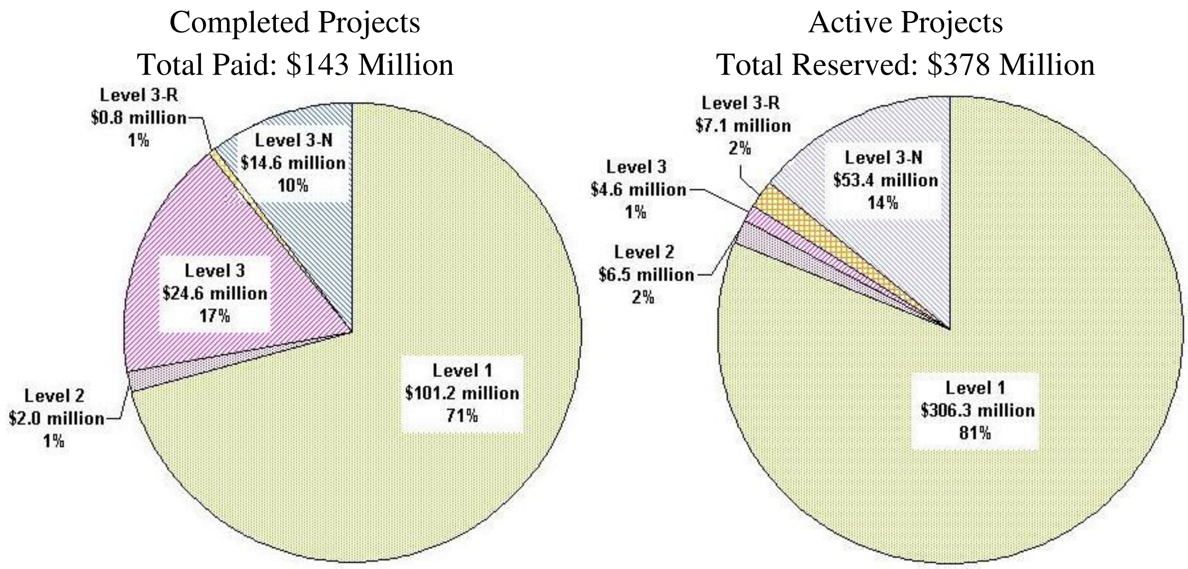
Incentive Level	Technology	IOU		MUNICIPAL		Total On-Line	
		(n)	(MW)	(n)	(MW)	(n)	(MW)
1	Photovoltaic	228	25.1	45	5.9	273	31.0
	Wind Turbine	1	1.0	0	0.0	1	1.0
2	Fuel Cell	2	0.8	0	0.0	2	0.8
3	Engine/Turbine	91	46.6	4	0.9	95	47.4
3-N	Engine/Turbine	64	34.6	2	0.6	66	35.2
3-R	Engine/Turbine	4	1.1	0	0.0	4	1.1
Total	**Total**	**390**	**109.1**	**51**	**7.4**	**441**	**116.5**

The Active but not yet on-line projects, representing 160 MW, are of secondary interest. They will influence sample design details in the future as additional projects come on-line.

4.3 Characteristics of Complete and Active Projects

The impact evaluation analysis is principally concerned with the on-line status of SGIP projects, rather than their status as "Complete" or "Active" (i.e., regardless of the status of the incentive payment). However, key aspects of SGIP project status tracked most closely by program implementers are differentiated by incentive payment status. SGIP incentives that have been paid or are reserved are summarized in Figure 4-2. The weighted average incentive for Complete and Active projects currently is $1.88/Watt.

Figure 4-2: Incentives Paid or Reserved for Complete & Active Projects



System Size Characteristics

Table 4-4 summarizes the system capacity characteristics of all Complete projects by technology and incentive level. Engines were installed for the largest completed SGIP projects. The smallest engine installed to date was 60 kW. The SGIP's minimum project size of 30 kW was just met by several PV and microturbine projects. Engine projects are typically several times larger than microturbine projects.

Table 4-4: Installed Capacities of PY01-PY04 Projects Completed by 12/31/2004

Incentive Level	Technology	System Size (kW)				
		n	Mean	Minimum	Median	Maximum
1	Photovoltaic	269	110	30	52	1,050
2	Fuel Cell	2	400	200	400	600
3	Engine	57	651	60	600	1,500
	Turbine	31	164	30	100	1,383
3-N	Engine	34	677	75	535	1,500
	Turbine	17	140	60	120	360
3-R	Engine	0	---	---	---	---
	Turbine	3	270	90	300	420

Table 4-5 summarizes the system capacity characteristics of all Active projects by technology and incentive level. In general, Complete Level 1 PV projects and Level 3/3-N engine projects tended to be slightly smaller than comparable Active projects in these incentive levels.

Table 4-5: Rated Capacities of PY01-PY04 Projects Active as of 12/31/2004

Incentive Level	Technology	System Size (kW)				
		n	Mean	Minimum	Median	Maximum
1	Photovoltaic	498	151	30	75	1,000
	Wind Turbine	5	664	60	710	1,000
	Fuel Cell	2	375	250	375	500
2	Fuel Cell	5	530	200	250	1,000
3	Engine	13	511	60	375	1,500
	Turbine	1	472	472	472	472
3-N	Engine	107	634	30	600	1,500
	Turbine	62	229	30	120	1,423
3-R	Engine	10	558	95	400	1,000
	Turbine	10	133	30	70	300

Total Eligible Project Costs

Total eligible project costs as regulated by SGIP guidelines cover the installed generating system and its ancillary equipment. Project cost data for Complete and Active PY01 through PY04 projects are presented in Table 4-6. The average per-Watt eligible project costs are weighted averages. PV projects account for the majority of total eligible project costs. Level 3/3-N engines combined account for the majority of Complete project capacity (MW), while Level 1 PV accounts for the majority of Active project capacity. Total eligible project costs (private investment plus the potential SGIP incentive) corresponding to Complete and Active PY01 through PY04 SGIP projects exceed $900 million.

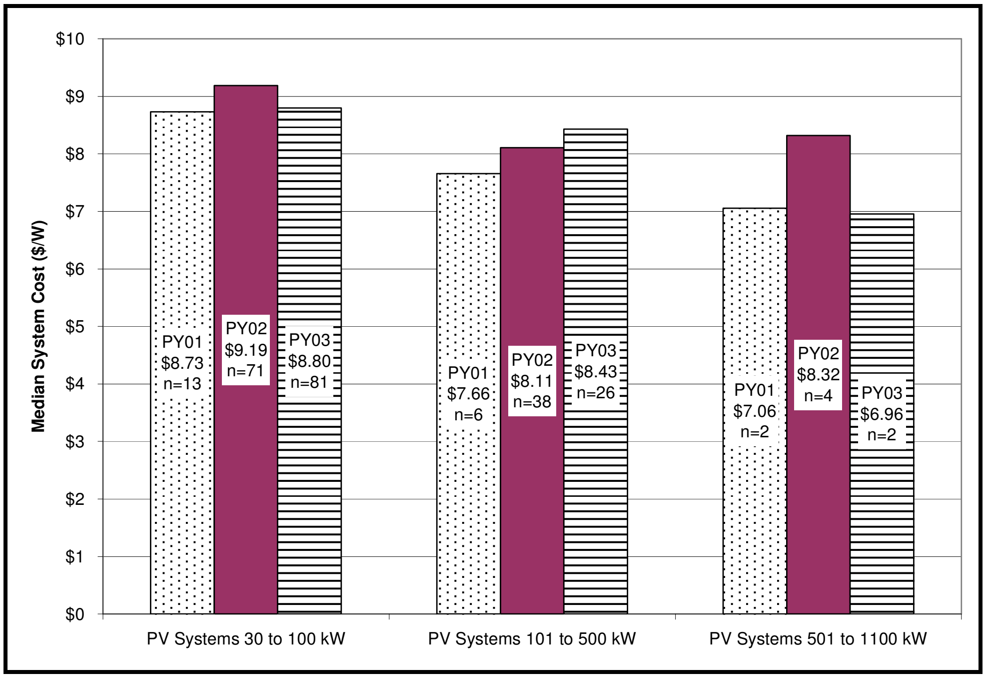
On a $/Watt basis the Level 1 PV projects are substantially more costly than the Level 3/3-N cogeneration projects. Any comparison of these project costs must take into consideration the fundamentally different characteristics of these technologies. In the case of cogeneration projects fueled with natural gas, ongoing fuel purchase and maintenance costs account for the majority of the lifecycle cost of ownership and operation. For PV systems, the capital cost is by far the most significant while the fuel is free and operations and maintenance costs are generally not as significant as those of cogeneration systems. In addition, Level 3 engines and turbines include both non-renewable and renewable-fueled projects, as there was no distinction between these two categories until mid-September 2002, when Levels 3-N and 3-R replaced Level 3.

Table 4-6: Total Eligible Project Costs of PY01 - PY04 Projects

Incentive Level	Technology	Complete Total (MW)	Complete Wt.Avg. ($/W)	Complete Total ($ MM)	Active Total (MW)	Active Wt.Avg. ($/W)	Active Total ($ MM)
1	PV	29.6	$8.30	$246	75.1	$8.45	$635
	Wind Turbine	0.0	$0.00	$0	3.3	$3.77	$13
	Fuel Cell	0.0	$0.00	$0	0.8	$9.37	$7
2	Fuel Cell	0.8	$9.82	$8	2.7	$7.71	$20
3	Engine	37.1	$2.07	$77	6.6	$2.57	$17
	Turbine	5.1	$2.79	$14	0.5	$4.71	$2
3-N	Engine	23.0	$2.17	$50	67.8	$2.52	$171
	Turbine	2.4	$2.93	$7	14.2	$3.14	$45
3-R	Engine	0.0	$0.00	$0	5.6	$2.43	$14
	Turbine	0.8	$2.95	$2	1.3	$4.42	$6
Total	**Total**	**98.8**	**$4.09**	**$404**	**177.9**	**$5.22**	**$929**

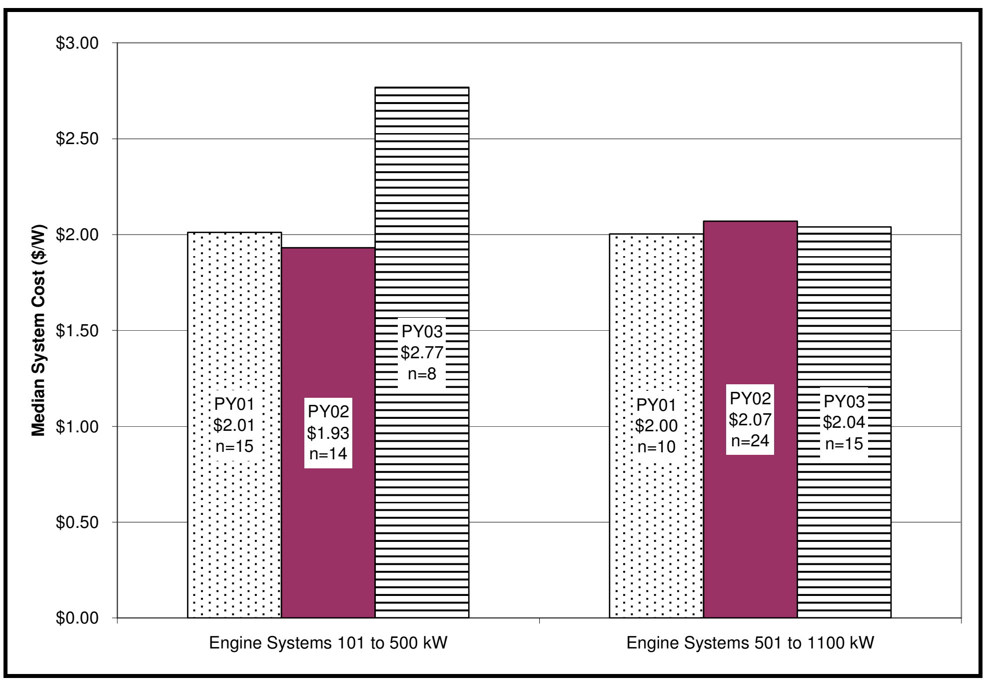
Costs of Complete and Active PV projects are presented in greater detail in Figure 4-3. On a per-Watt basis the larger systems tend to be less costly than the smaller systems. Some of these median cost results are based on small numbers of projects, however the data suggest that prices were either stable or rising.

Figure 4-3: Completed PV Projects - Total Eligible Project Cost Trend



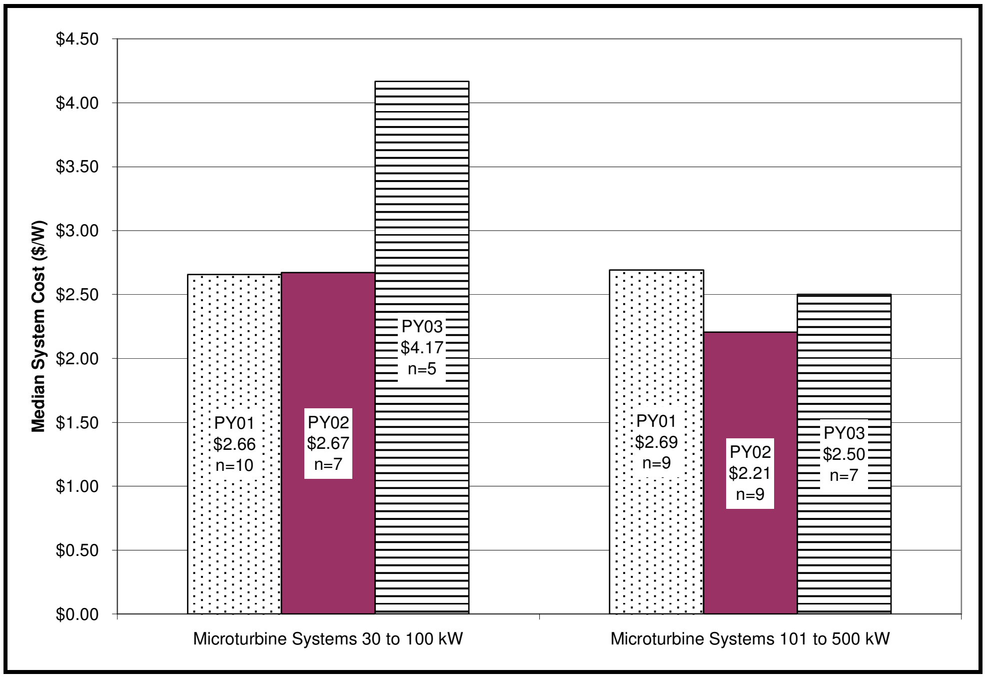
Median costs of natural gas engine projects are summarized in Figure 4-4. For the larger systems >500 kW the median of project costs was remarkably stable for PY01-PY03. The costs of smaller systems increased substantially during PY03.

Figure 4-4: Completed Natural Gas Engine Projects - Total Eligible Project Cost Trend



Median total eligible project costs of natural gas microturbine projects are summarized in Figure 4-5. For the 101 kW - 500 kW systems the median of project costs was relatively stable through PY01-PY03. The median of costs of smaller systems (≤ 100 kW) increased substantially during PY03, however this median is based on a small number of projects and the variability exhibited by the cost data is large. The costs of the 5 projects ranged from $2.17 to $7.76 per Watt; the mean was $4.22.

Figure 4-5: Completed Natural Gas Microturbine Projects - Total Eligible Project Cost Trend



Incentives Paid and Reserved

Incentives paid and reserved are presented in Table 4-7.[3] PV projects account for approximately 70% of the incentives paid for Complete projects, and 79% of the incentives reserved for Active projects.

New Level 3 projects entered the SGIP only through September 2002, at which time Level 3 was divided into Level 3-N and Level 3-R. Level 3 projects that were not Complete by the end of 2004 have been under development for more than two years. Some or all of these Active Level 3 projects may never be completed.

[3] The maximum possible incentive payment for each system is the system size (up to 1,000 kW) multiplied by the applicable dollar per kW incentive rate.

Table 4-7: Incentives Paid and Reserved

Incentive Level	Technology	Complete Incentives Paid			Active Incentives Reserved		
		Total (MW)	**Avg. ($/W)**	**Total ($ MM)**	**Total (MW)**	**Avg. ($/W)**	**Total ($ MM)**
1	PV	29.6	$3.42	$101.2	75.1	$3.96	$297.2
	Wind Turbine	0.0	---	$0.0	3.3	$1.72	$5.7
	Fuel Cell	0.0	---	$0.0	0.8	$4.50	$3.4
2	Fuel Cell	0.8	$2.50	$2.0	2.7	$2.46	$6.5
3	Engine	37.1	$0.56	$20.9	6.6	$0.62	$4.1
	Turbine	5.1	$0.72	$3.7	0.5	$1.00	$0.5
3-N	Engine	23.0	$0.55	$12.7	67.8	$0.63	$42.7
	Turbine	2.4	$0.77	$1.8	14.2	$0.75	$10.7
3-R	Engine	0.0	---	$0.0	5.6	$0.94	$5.2
	Turbine	0.8	$0.95	$0.8	1.3	$1.43	$1.9
Total	**Total**	**98.8**	**$1.45**	**$143.1**	**177.9**	**$2.12**	**$377.9**

Participant's Out-of-Pocket Costs After Incentive

Participant's out-of-pocket costs (total eligible project cost less the SGIP incentive) are summarized in Table 4-8. On a $/Watt rated capacity basis, Level 2 fuel cells have the highest cost, followed by Level 1 (renewable) fuel cells. The higher first cost of fuel cells is offset to some degree by their higher efficiency (reduced fuel purchases) and to a lesser degree by reduced air emission offsets. In certain instances, fuel cells also provide additional power reliability benefits that may drive project economics. PV is the next highest capital cost technology, followed by renewable-fueled microturbines and non-renewable fueled microturbines, respectively.

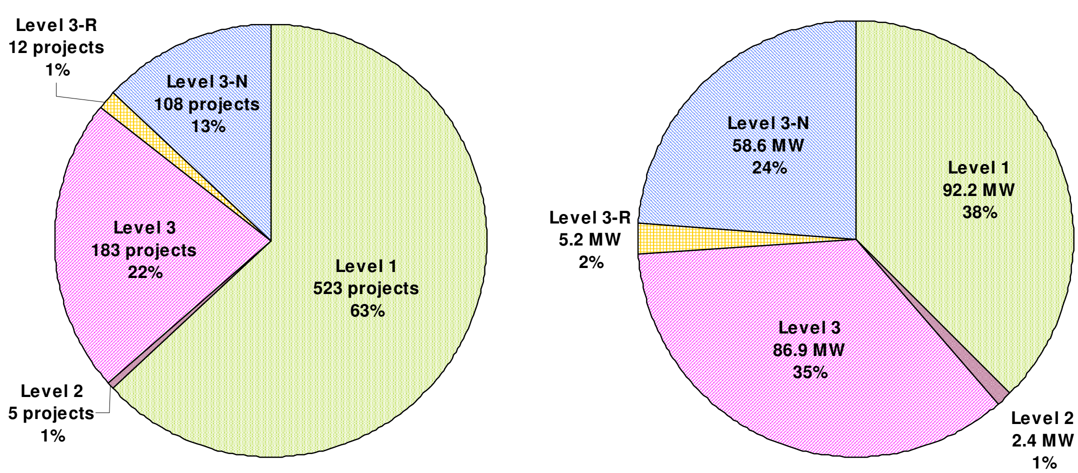
Table 4-8: SGIP Participant's Out-of-Pocket Costs After Incentive

Incentive Level	Technology	Complete			Active		
		Total (MW)	Avg. ($/W)	Total ($ MM)	Total (MW)	Avg. ($/W)	Total ($ MM)
1	PV	29.6	$4.88	$145	75.1	$4.49	$337
	Wind Turbine	0.0	---	---	3.3	$2.06	$7
	Fuel Cell	0.0	---	---	0.8	$4.87	$4
2	Fuel Cell	0.8	$7.32	$6	2.7	$5.25	$14
3	Engine	37.1	$1.51	$56	6.6	$1.95	$13
	Turbine	5.1	$2.07	$11	0.5	$3.71	$2
3-N	Engine	23.0	$1.61	$37	67.8	$1.89	$128
	Turbine	2.4	$2.16	$5	14.2	$2.39	$34
3-R	Engine	0.0	---	---	5.6	$1.49	$8
	Turbine	0.8	$2.00	$2	1.3	$2.99	$4
Total	**Total**	**98.8**	**$2.64**	**$261**	**177.9**	**$3.10**	**$551**

4.4 Characteristics of Inactive Projects

As of December 31, 2004, there were 831 Inactive projects (those either withdrawn or rejected), representing 245.4 MW of generating capacity. Figure 4-6 presents the status of these Inactive projects.

Figure 4-6: Number and Capacity (MW) of Inactive Projects



It is interesting to note the following from Figure 4-6:

- Level 1 projects constitute the largest share of number of Inactive projects (523 or 63%) and the largest share of total Inactive capacity (92.2 MW or 38%).
- Level 3/3-N projects account for the second largest share of number of Inactive projects (291 or 35%) and the second largest share of total Inactive capacity (145.5 MW or 59%).
- The 12 Inactive Level 3-R projects account for 5.2 MW of total Inactive capacity (2%).
- The five Inactive Level 2 projects make up the smallest share of Inactive projects, representing only 2.4 MW of total Inactive capacity (1%).

5

Program Impact Evaluation Sample Design

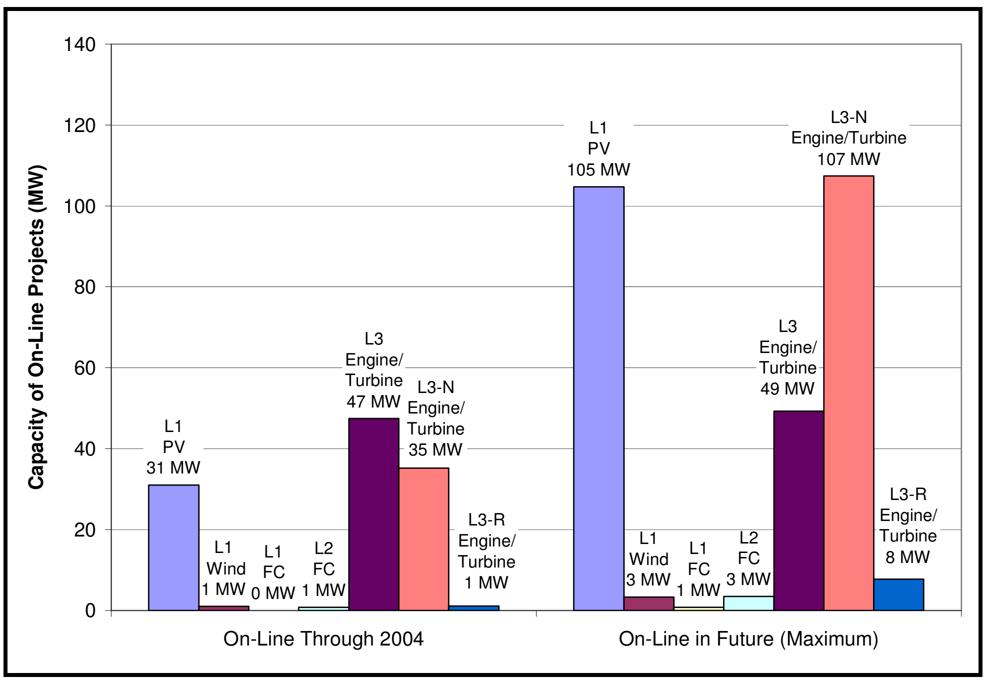
5.1 Introduction

This section addresses sample design issues related to collection of metered data from DG systems receiving incentives from the SGIP. First, a general overview of sample design issues is presented. Next, sample design strategies for PV and cogeneration systems are discussed. Finally, sample designs for all SGIP projects are summarized. Actual data collection outcomes are detailed in Section 7 of this report, System Monitoring and Operational Data Collection.

5.2 Overview

It is necessary to collect metered data from a certain portion of on-line SGIP projects to support the impact evaluation analysis. SGIP projects on-line as of December 31, 2004, were summarized previously in Figure 4-1 and Table 4-2. Figure 5-1 compares the capacity

Figure 5-1: Capacity of On-Line Projects Potentially Subject to Metering



of projects on-line through 2004 (totaling 116 MW across all Levels) with the future maximum potential capacity of all SGIP projects that were either Complete or Active (totaling 277 MW across all Levels) as of the end of 2004. This latter group defines the population of SGIP projects that could possibly be metered in the future, after all projects are built and are on-line. It is important to note, however, that it is possible that not all projects of this period (PY01-PY04) that are not yet on-line will be built.

Specification of the sample design for program impact evaluation purposes involves selecting certain projects for which metered data are desired. A discussion of general sample design considerations was included as Section 5 of the SGIP third-year impact evaluation report. The analysis underlying development of sample designs for PV systems and natural gas metering was presented. Key elements of the discussion for PV and cogeneration systems are included below.

5.3 Level 1 PV Systems

Initial plans called for collection of interval-metered electric net generator output (ENGO) data from all Level 1 PV systems in the SGIP. These plans were described in the program's second-year impact evaluation report. The program's third-year impact evaluation report included examination of the possibility of sampling PV systems. Subsequent discussions with the SGIP Working Group led to an agreement that all of the Program Administrators would continue to ensure that ENGO data are available for all Level 1 ≥ 300 kW PV systems.

The plans for ≥ 300 kW PV systems were not driven strictly by program impact evaluation accuracy considerations. Program Administrators are concerned about the performance of PV systems of this size because of the very large capital investments they represent. Not surprisingly, to date all SGIP PV systems of this size have been equipped with meters by the equipment vendor or the system owner.

The sample design for <300 kW PV systems includes metering of all PV systems that entered the program in PY01 or PY02, regardless of size (as called for in initial plans). Metering all of these systems allows the exploration of the possibility that performance differences exist between those PV systems already equipped with interval-metering equipment by the PV system supplier and those PV systems that would otherwise include little or no provision for performance monitoring.

Impact Measure of Interest

Assessment of the effect of sampling of PY03-PY04 <300 kW PV projects on the accuracy of estimates of SGIP impact was based on PV AC power output during hours when CAISO loads reached maximum values. This basis was selected because a principal objective of the SGIP is to deliver generation capacity benefits during system peaking conditions. Furthermore, this treatment is expected to provide a more conservative result than would a sample design analysis based on totalized electric energy production for either seasons or years. During these longer periods of time factors that can greatly affect output for isolated hours (e.g., a single thunderstorm, a short-term inverter problem or shade from particular obstructions) tend to average out.

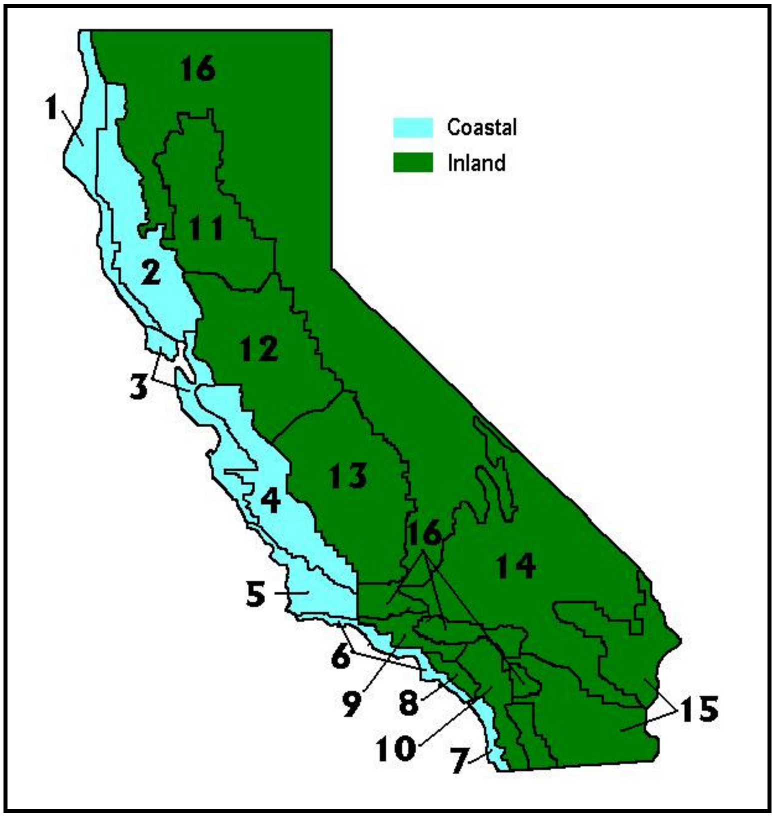
Sampling Strata

Only a portion of <300 kW PV systems that entered the program in PY03 or PY04 will be metered. For these systems, several key stratifying parameters were used in the assessment of sampling on the accuracy of impact estimates. These parameters are presented in Table 5-1 and Figure 5-2.

Table 5-1: Stratifying Parameters for PY03 - PY04 PV Systems <300 kW

Parameter	Strata
Program Administrator	PG&E, SCE, SoCalGas, SDREO
PV Orientation	Near-Flat: Module tilts less than 20º (any azimuth) Other: All other tilts (incl. tracking systems)
Location	Coastal: Zones 1 through 7 in Figure 5-2 Inland: Zones 8 through 16 in Figure 5-2

Figure 5-2: Coastal versus Inland Assignment Map for PV Systems



5.4 Incentive Level 3 & 3-N Cogeneration Systems

Program evaluation plans continue to include collection of ENGO data from all non-PV PY01-PY04 SGIP projects. However, in addition to specifying of electric metering requirements, sample design for cogeneration systems must also address fuel input and recovery of heat subsequently applied to useful purposes. Due to the planned census for ENGO metering, the sample design assessment for Level 3 and 3-N cogeneration systems was limited to examination of possibilities for fuel and heat metering sampling.

Impact Measures of Interest

Electric impact considerations for cogeneration systems are identical in kind to those discussed above for PV systems. The principal impact measures of interest unique to cogeneration systems include heat recovery rates and several measures of efficiency. These impact measures are identified and described below in Table 5-2. As all four performance measures outlined below are very important, sample designs for cogeneration systems should yield meaningful results for all four system impact measures.

Table 5-2: Cogeneration System Impact Measures

Impacts Measure	Importance
PUC 218.5(b) System Efficiency	Prior to construction, each cogeneration system in the program is required to demonstrate with engineering calculations that system's ability to achieve minimum system efficiencies prescribed by the PUC. This measure represents a significant program eligibility benchmark.
Overall System Efficiency	In the distributed generation literature it is customary to reference overall system efficiencies achievable when both electricity and useful thermal energy are produced by the system. This measure represents a significant performance benchmark that can be used to compare cogeneration system performance against the performance of alternative technologies.
Electrical Conversion Efficiency	Electrical conversion efficiency is a particularly important element of the PUC 218.5(b) system efficiency, because in that equation electrical energy is credited at a rate of 100% whereas heat is credited at the lesser rate of 50%. Electrical conversion efficiency is also important because it represents a significant component efficiency that can be used to compare actual performance against expected performance.
Heat Recovery Rate	Expressed in terms of kBtu/kWh, this measure of system performance is particularly important because it is likely to vary across application types (e.g., space heating versus absorption chiller for process cooling), and relatively little related field data are currently available.

Sampling Strata

Specification of sampling strata is dictated in part by factors governing variability. These factors are different for the several key impact measures of interest. Factors influencing variability exhibited by electrical conversion efficiency and heat recovery rate are discussed below. These two impact measures are combined to yield the other system efficiency impact measures described above.

<u>Electrical Conversion Efficiency:</u> For the purposes of PY01-PY04 SGIP impact evaluation sample design, technology type (i.e., engine, turbine) was selected as the sole stratifying variable for electrical conversion efficiency. Fuel use data available from meters installed and operated by SGIP participants and their natural gas utility companies are sufficient to adequately support impact evaluation analyses.

<u>Heat Recovery Rate:</u> Numerous factors could conceivably be used to stratify cogeneration systems for purposes of monitoring useful thermal energy recovery. Several possibilities are listed below.

- End use for heat (space/process heat, space/process cooling)
- Operating schedule (year round, summer only, non-summer only)

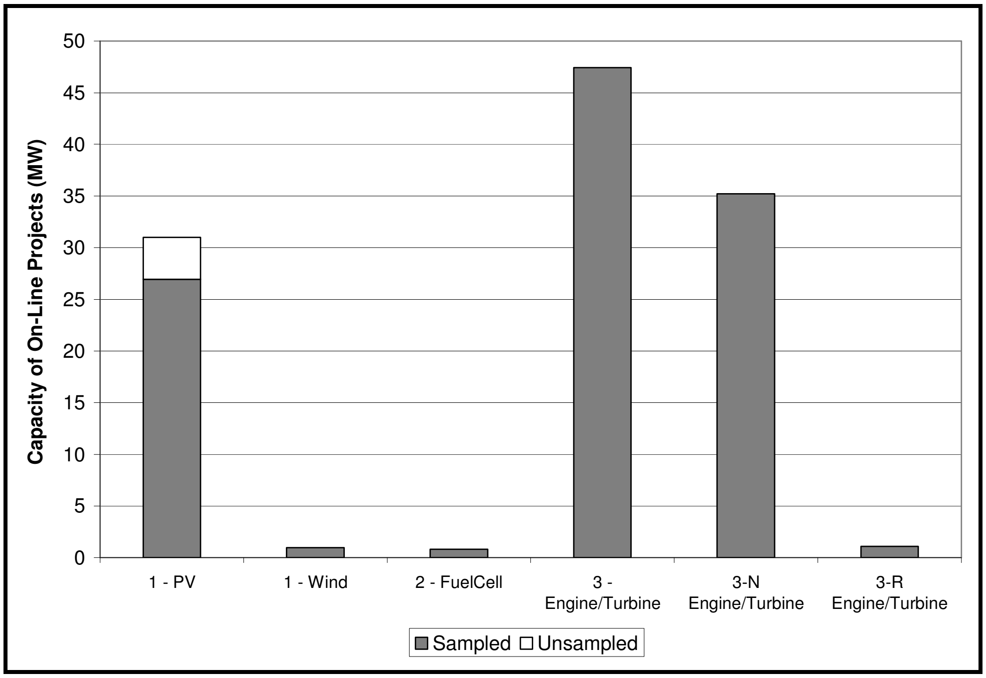
- Size of cogeneration system relative to size of facility electrical and heat loads
- Design of heat recovery system (hardware and software)
- Operating effectiveness of heat recovery system (hardware and software)

For this program impact evaluation project, no stratification of cogeneration systems is being performed for purposes of monitoring useful thermal energy recovery. This decision was based on two key factors. First, there are a large number of potentially significant stratifying factors relative to the total number of available cogeneration systems. Second, the quantity of heat recovery data collected to date is relatively small, and those existing data suggest that recovery of useful heat is quite variable. Therefore, projects have been selected for metering based solely on their on-line status. The objective is to install heat-metering equipment as soon as possible after they come on-line, subject to constraints imposed by the program evaluation's overall schedule and budget. These constraints will limit the monitoring of heat recovery to approximately the first 130 on-line projects.

5.5 Conclusion

The link between project status information from Figure 5-1 and results of the program impact evaluation sample design analysis is depicted graphically in Figure 5-3 through Figure 5-5. The sample design for ENGO metering of projects on-line through 2004 is summarized in Figure 5-3. Metering of all non-PV projects is planned. Metering of all PV systems ≥300 kW is planned, along with metering of many of the PV projects <300 kW. As of December 31, 2004, no plans are in place to meter output of 66 PY01-PY04 PV projects corresponding to 4.0 MW of rebated capacity. Program impact yielded by these unmetered PV systems will be estimated using methods discussed in Section 8.

Figure 5-3: ENGO Sample Design for Projects On-Line Through 2004

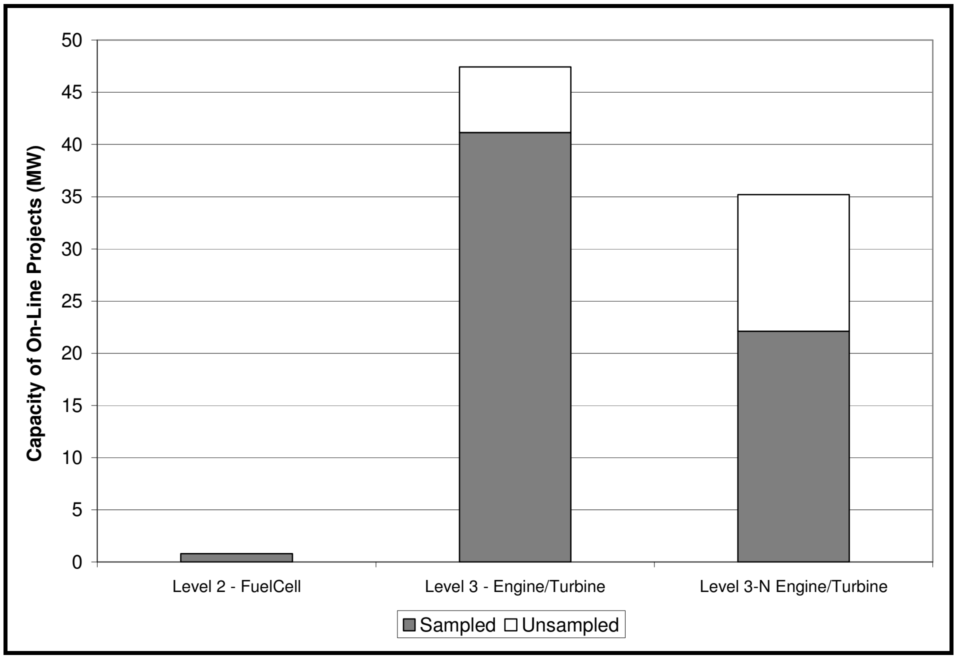


For PY2003 and PY2004 PV projects <300 kW metered data received from SGIP participants and other third parties will be sufficient to yield impact estimates of sufficient accuracy for program evaluation purposes. Other than occasional spot metering for verification purposes, it is not essential that the Program Administrators have their metering contractors install ENGO metering on PY2003 and PY2004 PV systems that are smaller than 300 kW. However, important SGIP-related issues other than PA-level total demand impact may result in Program Administrators directing metering subcontractors to install metering on certain otherwise unmetered PY03 or PY04 PV projects.

Current electric utility plans call for ENGO metering of all cogeneration systems for tariff purposes; therefore it is not necessary to examine ENGO sampling at this time. Depending on regulatory and other events it may be advantageous to reevaluate this approach in the future.

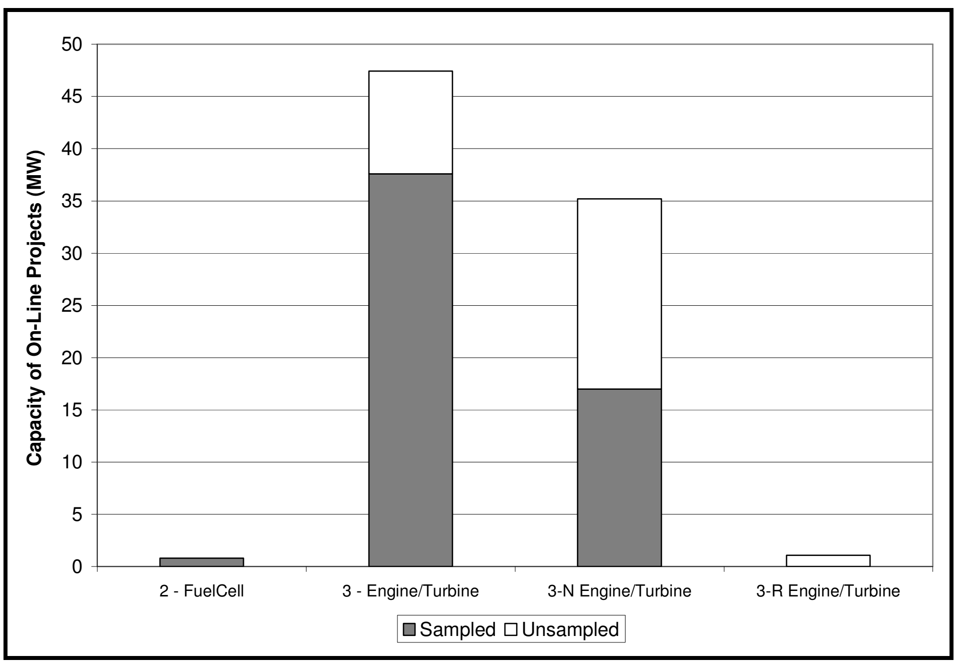
The sample design for HEAT metering of projects on-line through 2004 is summarized in Figure 5-4. The different monitoring rates for Level 3 and Level 3-N projects are merely the result of Level 3 projects entering the program earlier and being likely to have come on-line before many of the Level 3-N projects.

Figure 5-4: HEAT Sample Design for Projects On-Line Through 2004



The sample design for fuel consumption (FUEL) metering of projects on-line through 2004 is summarized in Figure 5-5. Fuel metering effected by utility companies, Hosts, Applicants, and vendors will be sufficient. It is not essential that Program Administrators continue to install additional fuel metering solely for program evaluation purposes. Level 3-R projects on-line through 2004 utilized 100% renewable fuel and therefore did not require fuel meters.

Figure 5-5: FUEL Sample Design for Projects On-Line Through 2004



6

Fourth-Year Impact Evaluation Data Collection Activities

An overview of the range of data collection activities supporting the fourth-year impact evaluation is presented in this section. A description of metered data collection issues and current status is included in Section 7.

6.1 Administrator Program Tracking Database & Handbook Updates

Administrators provided program evaluators regular updates of their program tracking database files. These files contain information that is essential for planning and implementing data collection activities supporting the impact evaluation. Information of particular importance includes basic project characteristics (e.g., incentive level, technology, size, fuel) and key participant characteristics (e.g., Host and Applicant names[1], addresses, and phone numbers). The program evaluator's initial M&E activities for each project were influenced by the project's technology type, program year, and Program Administrator. The program stage of each project was tracked by the program evaluator, and M&E activities initiated accordingly. Updated SGIP handbooks were used for planning and reference purposes.[2]

6.2 Electric Net Generator Output (ENGO) Interval Data Collection

ENGO data collection activities for the fourth-year impact evaluation were aimed at obtaining available data from Hosts, Applicants, and electric utilities. This effort was complicated by several factors. As of the end of 2004, not all administrators had yet

[1] The Host Customer is the customer of record at the site where the generating equipment is or will be located. An Applicant is a person or entity who applies to the Program Administrator for incentive funding. Third parties (e.g. a party other than the Program Administrator or the utility customer) such as engineering firms, installing contractors, equipment distributors or Energy Service Companies (ESCO) are also eligible to apply for incentives on behalf of the utility customer, provided consent is granted in writing by the customer.

[2] SGIP Handbooks are available on Program Administrator Web sites.

completely implemented plans for wide-scale installation and operation of net generator output meters. Two administrators retained the program evaluation contractor to install ENGO metering for a portion of their projects in conjunction with useful thermal energy metering installations, however the latter activity was delayed for several months due to an interruption in the contractual arrangements under which the work is performed.

The meter installation interruption was longer than expected because each of the incremental steps in the contracting process required more time than anticipated. First, Itron developed a revised work plan. Next the Program Administrators worked with the M&E Program Manager to revise their co-funding agreement. Third, a new purchase order between Itron and the statewide M&E Program Manager was negotiated. Finally, contractual agreements between Itron and its subcontractors were negotiated. As a result of these and other similar issues the ENGO interval data archive is incomplete. However, substantial quantities of ENGO data for 2004 were ultimately collected, as summarized in Section 7. Analytic methodologies used to estimate electric impacts of projects for which ENGO data were not available are discussed in Section 8.

6.3 Useful Thermal Energy Data Collection

Useful thermal energy data collection typically involves an invasive installation of monitoring equipment (i.e., flow meters and temperature sensors). Therefore, a significant effort was undertaken to minimize the unnecessary installation of this equipment. Many third parties or Hosts had this equipment installed at the time of system installation, either as part of their contractual agreement with a third party vendor or for internal process/energy monitoring purposes. In many cases the program evaluation contractor was able to obtain the relevant data these Hosts and third parties were already collecting. This approach minimized both the cost- and disruption-related risks of installing monitoring equipment. The majority of useful thermal energy data for 2004 were obtained in this manner.

The statewide evaluation contractor began installing useful thermal energy and fuel usage metering in the summer of 2003. The first nine useful thermal energy meters and the first five fuel usage meters were installed by December 2003. Metering installation was put on hold for more than six months (late-fall 2003 - summer 2004) while the several contractual arrangements underlying the work were revised to extend its term. The remaining Complete projects for which monitoring equipment has not yet been installed are in the process of monitoring plan preparation and monitoring equipment procurement.

Only modest quantities of useful thermal energy data for 2004 were collected, as detailed in Section 7. Fuel usage data were available from gas utilities for a substantial number of projects, however. These data in combination with available ENGO data enable development of useful information related to electrical conversion efficiencies, which are a key contributor to overall system efficiencies. Analysis of the available data related to heat recovery and system efficiencies is discussed in Section 8.

6.4 Fuel Usage Data Collection

Fuel usage data collection activities completed to date have involved natural gas monitoring. In the future it may also be necessary to monitor consumption of gaseous renewable fuel to assess compliance with renewable fuel usage requirements in place for Level 1 fuel cell and Level 3-R engine/turbine projects. To date, all such on-line projects have utilized only 100% renewable fuel.

The natural gas usage data used in the fourth-year impact evaluation were obtained from natural gas utilities, SGIP participants, and natural gas metering installed by the program evaluation contractor. The data were reviewed and their bases documented prior to processing into a data warehouse. Reviews of data validity included combining fuel usage data with power output data to check for reasonableness of gross engine/turbine electrical conversion efficiency. In cases where validity checks were failed the data provider was contacted to further refine the basis of data. In some cases it was determined that data received were for a facility-level meter rather than from metering dedicated to the SGIP cogeneration system.

6.5 System Owner Survey of System Performance and O&M Experience

Previous process evaluations have included telephone surveys of program participants to explore various aspects of their SGIP experience. Participants at all stages of the SGIP implementation process were surveyed. For this fourth-year impact evaluation study a telephone survey was conducted. As opposed to previous efforts, this survey focused on projects for which a substantial quantity of metered data were in hand, and results of analysis of those data were referenced in the survey instrument. This increased the probability that collected information pertaining to system performance was based on an accurate understanding of actual system performance. This survey also was used to collect information capable of explaining information suggested by metered data. For example, some of the cogeneration systems were observed to have been idle during certain portions of 2004. An objective of the survey was to determine whether these idle periods were attributable to unfavorable fuel prices, unscheduled maintenance or other factors. Similarly, performance of some of the PV systems was observed to have deteriorated through time. An objective of the survey was to determine whether these PV systems were being cleaned regularly in an effort to understand the link between system performance and maintenance practices.

6.6 On-site Verification Facility Data Collection

During metering and data collection site visits, the on-site evaluation subcontractor[3], collected facility information necessary to complete the project-specific metering and data collection plan in support of the impact evaluation. Meter nameplate information was recorded for meters used for billing purposes, as well as those used for information purposes. The date the system entered normal operations was also determined (or estimated) from the available operations data, as required. Information collected by the on-site evaluator for Program M&E purposes augmented that developed by the Program Administrators' installation verification site inspectors. Inspection Reports produced by these independent consultants were provided to the program evaluator regularly, and their review contributed significantly to the project-level M&E planning efforts.

[3] Brown,Vence & Associates, Inc. (BVA), subcontractor to the program evaluator

7

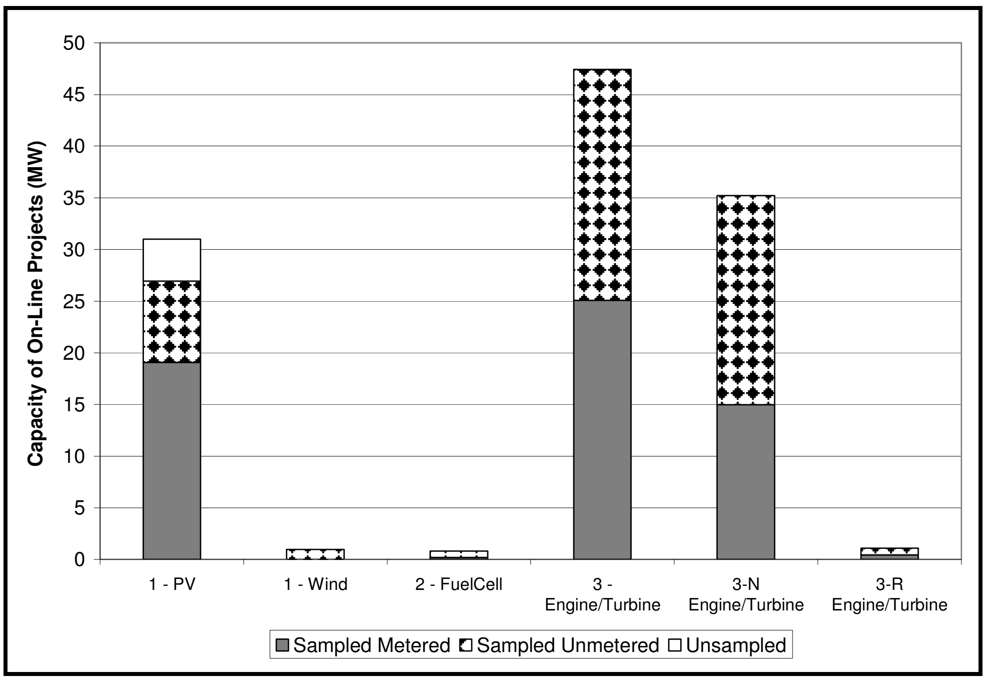
System Monitoring and Operational Data Collection

Data Collection Status Summary

As of the end of 2004, 441 PY01-PY04 SGIP projects were determined to be on-line. These projects correspond to 116 MW of SGIP project capacity. It is necessary to collect metered data from a certain portion of on-line projects to support the impact evaluation analysis. In Section 5 of this report sample designs for useful thermal energy recovery (HEAT), fuel consumption (FUEL), and electric net generator output (ENGO), were outlined. This section presents summaries of actual data collection based on availability of metered data in December 2004.

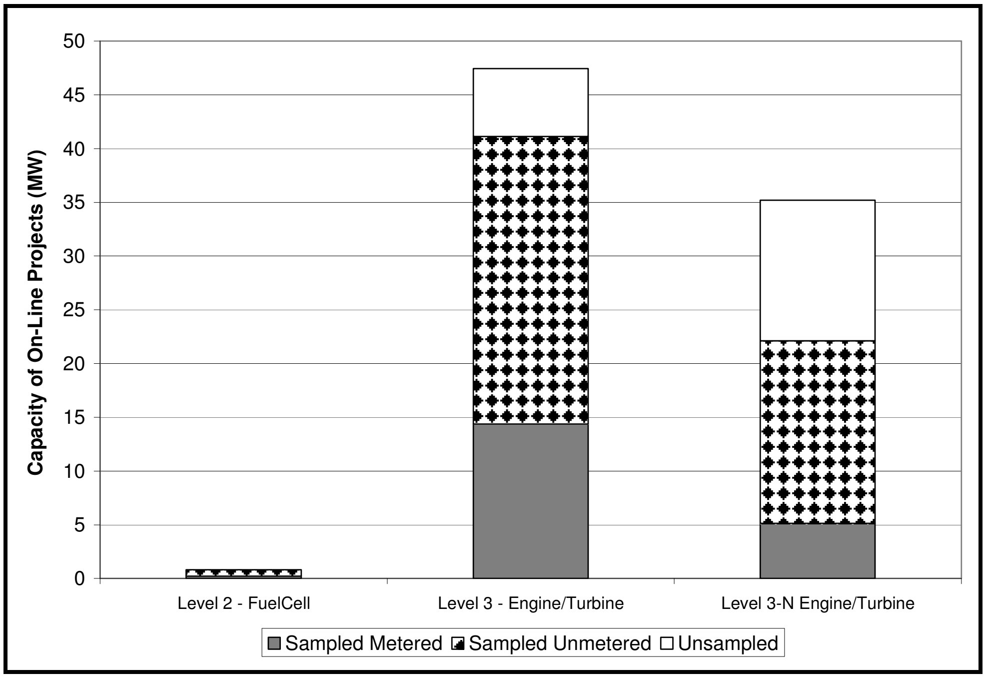
The status of ENGO data collection is summarized in Figure 7-1. A substantial quantity of ENGO metering installation activity remains to be completed. This activity is ongoing and is being carried out by the Program Administrators and the SGIP evaluation contractor.

Figure 7-1: ENGO Data Collection as of 12/31/04



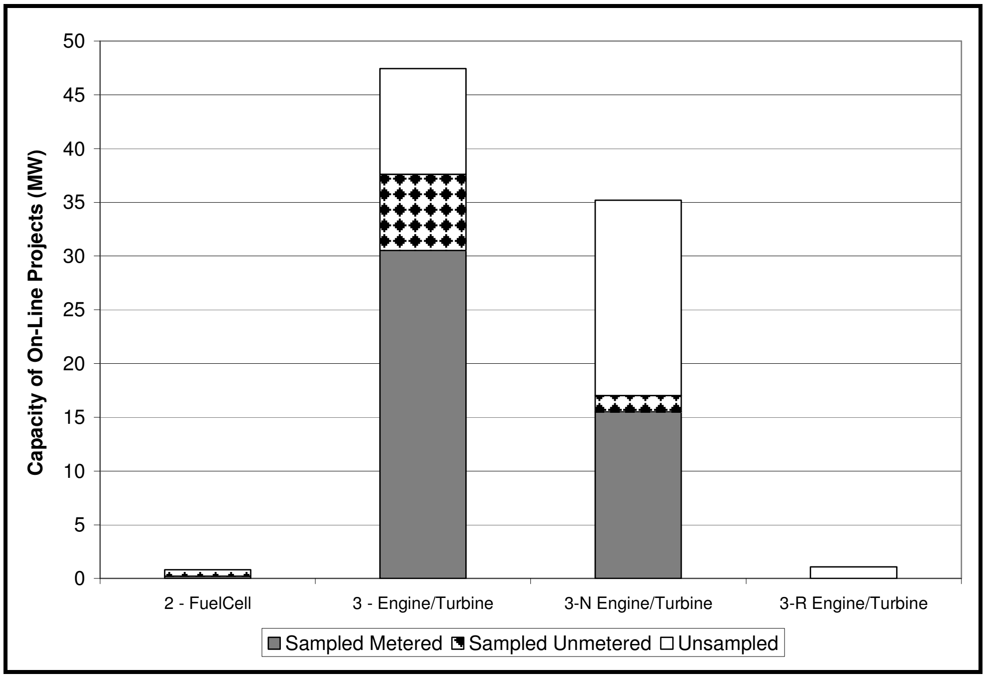
The status of HEAT data collection is summarized in Figure 7-2. Heat recovery data have been obtained for less than half of the project capacity slated for HEAT metering. The pace of HEAT metering installation increased considerably in the first quarter of 2005 as progress is made toward achieving the planned monitoring rate.

Figure 7-2: HEAT Data Collection as of 12/31/04



The status of FUEL data collection is summarized in Figure 7-3. Most of the FUEL data have been obtained from IOUs. A principal use of these data is to support calculation of electrical conversion efficiencies and cogeneration system efficiencies.

Figure 7-3: FUEL Data Collection as of 12/31/04



Additional data collection activities currently underway include finalizing remaining metering plans and installing on-site data acquisition systems for on-line projects. Collection and validation of data from already-established data providers will continue as well. These data gathering efforts will continue at least through the end of 2005.

8

System Impacts and Operational Characteristics

8.1 Introduction

This section addresses the 2004 peak demand and energy impacts of the on-line SGIP projects for PY01-PY04. Electrical demand and energy impacts were estimated for on-line projects regardless of their stage of advancement in the program. Impact estimates are therefore based on projects for which SGIP incentives have already been disbursed (Complete projects), as well as on operational projects that have yet to complete the SGIP process (on-line Active projects).

While the sample design calls for all operational (or "on-line") non-PV projects and most operational PV projects to be metered, as of the end of 2004 about 50% of on-line PY01-PY04 projects were not yet equipped with generator output electric meters (or data were not yet available to the evaluation contractor from third parties). Consequently, this annual impact evaluation relies on a combination of metered data, statistical methods, and engineering assumptions. Data availability and corresponding analytic methodologies vary by program level and technology, as described in subsections 8.3 through 8.7.

8.2 Overall Program Impacts

Electrical demand and energy impacts were calculated for Complete and Active projects that began normal operations prior to December 31, 2004, using available metered data and other system characteristics information from the program tracking systems maintained by the Program Administrators (PA).

Peak Demand Impact

Overall program demand impact coincident with 2004 CAISO system peak load are summarized below in Table 8-1. In 2004 the CAISO system peak reached a maximum value of 45,562 MW on September 8 during the hour from 3:00 to 4:00 p.m. (PDT). There were 388 SGIP projects known to be on-line when the CAISO experienced this summer peak, but generator electric interval-metered data were available for only 182 of them. While the total on-line capacity of the 388 operational projects exceeded 103 MW, the total impact of the SGIP projects coincident with the CAISO peak load is estimated at just under 55 MW

(54,797 kW). Level 3/3-N/3-R engines and microturbines account for 81% of the 2004 peak demand impact.

Table 8-1: Demand Impact Coincident with 2004 CAISO System Peak Load

Level / Basis	On-Line Systems (n)	On-Line Capacity (kW)	Peak Demand Impact (kW_P)
Level 1 PV	**235**	**25,365**	**9,938**
Metered	107	16,056	6,292
Estimated	128	9,308	3,646
Level 1 Wind	**1**	**950**	**0**
Metered	0	0	0
Estimated	1	950	0
Level 2 Fuel Cell	**2**	**800**	**744**
Metered	1	200	196
Estimated	1	600	548
Level 3/3-N/3-R Engine/Turbine	**150**	**75,930**	**44,115**
Metered	74	34,900	20,198
Estimated	76	41,030	23,917
Total	**388**	**103,045**	**54,797**

Energy Impact

Overall program electrical energy impact is summarized in Table 8-2.

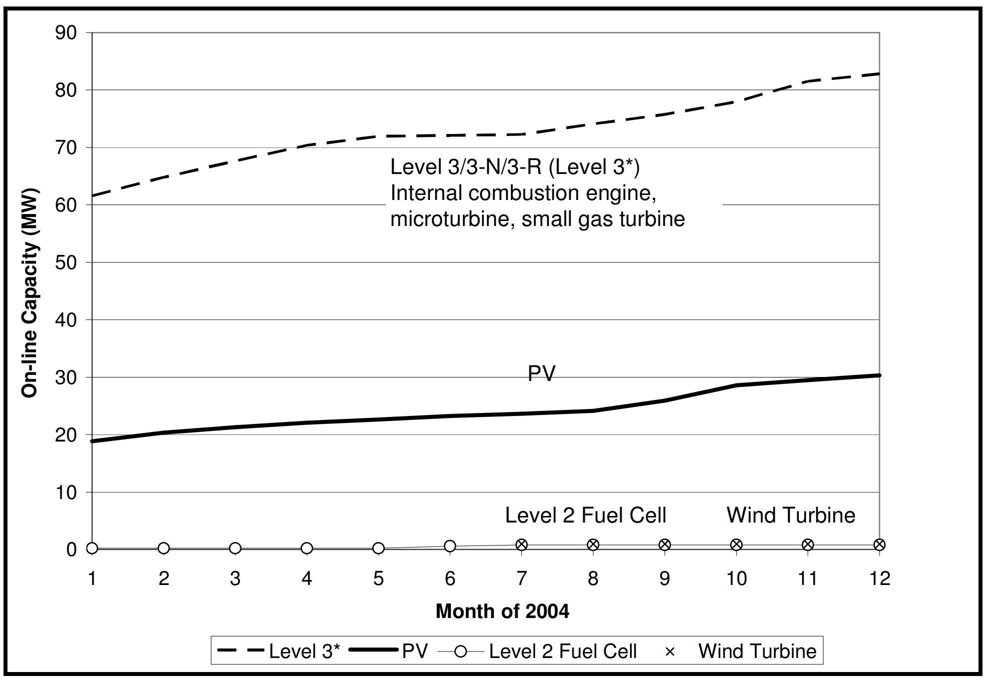
Table 8-2: Energy Impact in 2004 by Quarter (MWh)

Level / Basis	Q1-2004	Q2-2004	Q3-2004	Q4-2004	Total
Level 1 PV	**5,612**	**11,020**	**10,649**	**6,553**	**33,835**
Metered	3,467	6,984	6,976	4,194	21,620
Estimated	2,145	4,036	3,673	2,360	12,215
Level 1 Wind	**0**	**0**	**0**	**339**	**339**
Metered	0	0	0	0	0
Estimated	0	0	0	339	339
Level 2 Fuel Cell	**422**	**689**	**1,616**	**1,559**	**4,286**
Metered	422	403	356	349	1,530
Estimated	0	286	1,260	1,209	2,755
Level 3/3-N/3-R Engine/Turbine	**63,276**	**72,488**	**79,856**	**70,574**	**286,193**
Metered	40,777	46,906	49,633	35,613	172,929
Estimated	22,499	25,582	30,223	34,960	113,264
Total	**69,311**	**84,197**	**92,120**	**79,025**	**324,653**

While Level 3/3-N/3-R engines and turbines account for 81% of demand impacts, they account for 88% of total energy impact. This difference is due to the fact that the average capacity factor of these engines and turbines is greater than that for the Level 1 PV systems. During 2004 the quarterly energy impact increased through the third quarter before falling during the fourth quarter. Although additional generation capacity was coming on-line throughout the year, related effects were offset by factors such as the seasonal variability in PV energy production and the influence of natural gas prices on cogeneration system operations.

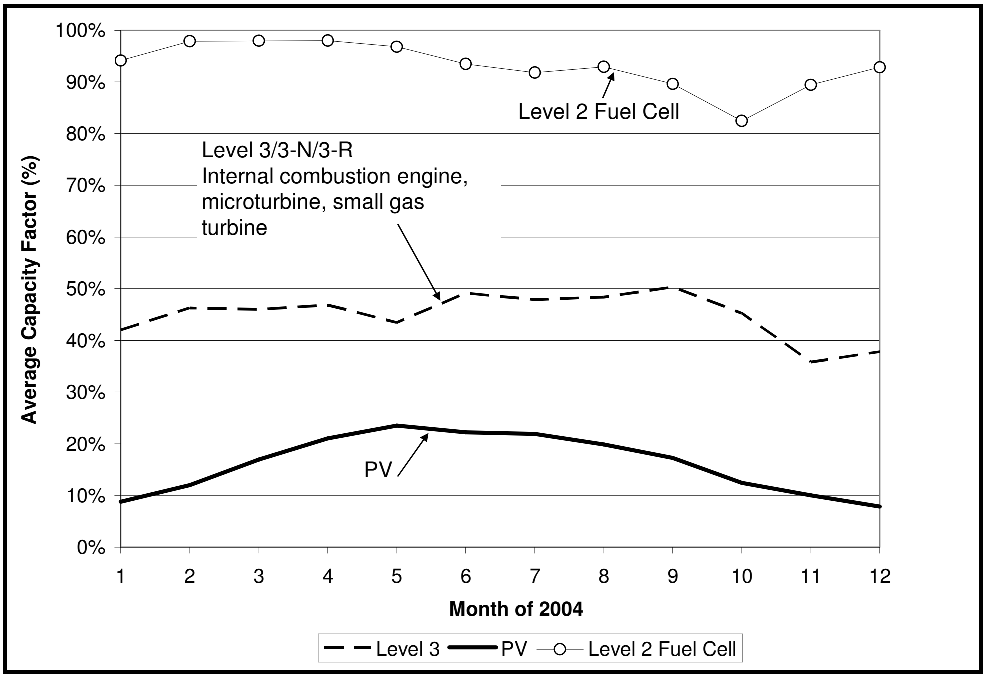
The program impact evaluation effort is influenced by the additional SGIP projects which come on-line on a regular basis. The related increase in on-line capacity during 2004 is depicted graphically in Figure 8-1. This chart also illustrates the relative quantities of project capacity for the various technologies by incentive level included in the SGIP.

Figure 8-1: On-Line Capacity by Month (2004)



In Figure 8-2, the energy production characteristics of the on-line systems are expressed on a normalized basis (i.e., monthly capacity factor) to enable comparison of the different distributed generation technologies by SGIP incentive level. Additional details concerning these energy production characteristics are discussed in subsequent portions of this section.

Figure 8-2: Average Capacity Factor by Month (2004)



8.3 Level 1 PV Systems

Available system output data were used in the analysis directly. These data were also combined with certain known characteristics of projects (e.g., location, array tilt and orientation angles, system size) to estimate peak demand and energy impacts of the un-metered PV systems. Available metered data were used to calculate ratios representing average PV system power output per unit of rebated system capacity. Ratios were calculated separately for each of the sample design strata discussed in Section 5.[1] For periods when no metered data were available, estimates of PV system power output were calculated as:

$$EN\hat{G}O_{psdh} = \left(S_{ps}\right)_{Unmetered} \times \left(\frac{\sum ENGO_{psdh}}{\sum S_{ps}}\right)_{Metered}$$

Where:

$EN\hat{G}O_{psdh}$ = Predicted net generator output for project *p* in strata *s* on day *d* during hour *h*

Units: kWh

Source: Calculated

[1] Due to data availability limitations, data available for SCE and SoCalGas PV systems were combined in the 2004 estimation calculations rather than being treated separately. In the future when data collection conforms to the sample design summarized in Section 5, it will not be necessary to combine strata in this manner.

S_{ps} = Solar PV system size for project *p* in strata *s*

Units: kW
Source: SGIP Tracking System

$ENGO_{psdh}$ = Metered net generator output for project *p* in strata *s* on day *d* during hour *h*

Units: kWh
Source: Net Generator Output Meters

Demand Impact Coincident with CAISO Peak

As stated above, in 2004 the CAISO system peak occurred on September 8 during the 16th hour (from 3:00 to 4:00 p.m. (PDT)). During this hour the electrical demand for the CAISO reached 45,562 MW. On this day there were 235 SGIP PV systems installed and on-line; interval-metered data are available for 111 of them. Resulting estimates of peak demand impact coincident with the CAISO peak load are summarized in Table 8-3. The estimated peak demand impact corresponds to 0.39 kW per 1 kW of PV system size (basis: rebated capacity). The total program-level system peak demand impact for Level 1 PV systems is estimated to have been 9,938 kW (approximately 10 MW).

Table 8-3: Impact of Level 1 PV Projects Coincident with 2004 CAISO Peak

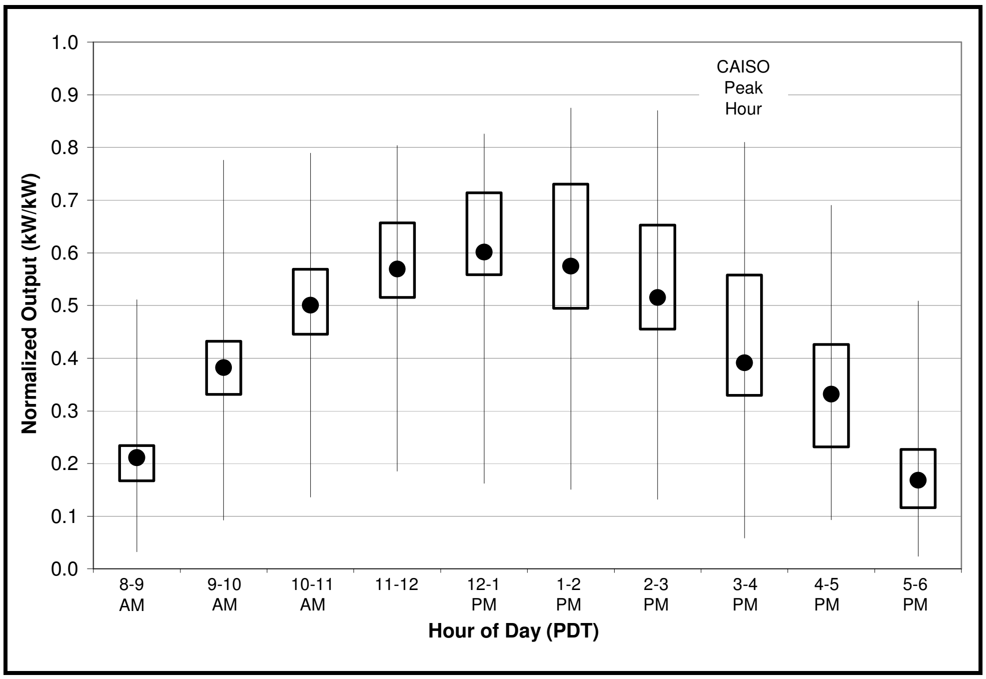
Output Basis	On-Line Systems (n)	On-Line Capacity (kW)	Peak Demand Impact (kW_P)
Metered	107	16,056	6,292
Estimated	128	9,308	3,646
Total	**235**	**25,365**	**9,938**

Those unfamiliar with PV system size ratings and PV system operating characteristics may be surprised that the overall weighted-average peak demand impact was not substantially higher than 0.39 $kW_P/kW_{rebated}$. In fact this result is not unexpected. Factors explaining this result are discussed in detail in Appendix A, PV System Performance Details.

The peak-day operating characteristics of the 107 PV projects for which peak-day interval-metered data were available are summarized in the box plot of Figure 8-3. System sizes were used to normalize power output values prior to plotting summary statistics of PV output data for individual projects. The normalized values represent PV power output per unit of system size. Treatment in this manner enables direct comparison of the power output characteristics of PV systems of varying sizes. The vertically oriented boxes represent ranges within which 75% of project-specific values lie. The vertical lines represent the total range (i.e., maximum and minimum) of project-specific values.

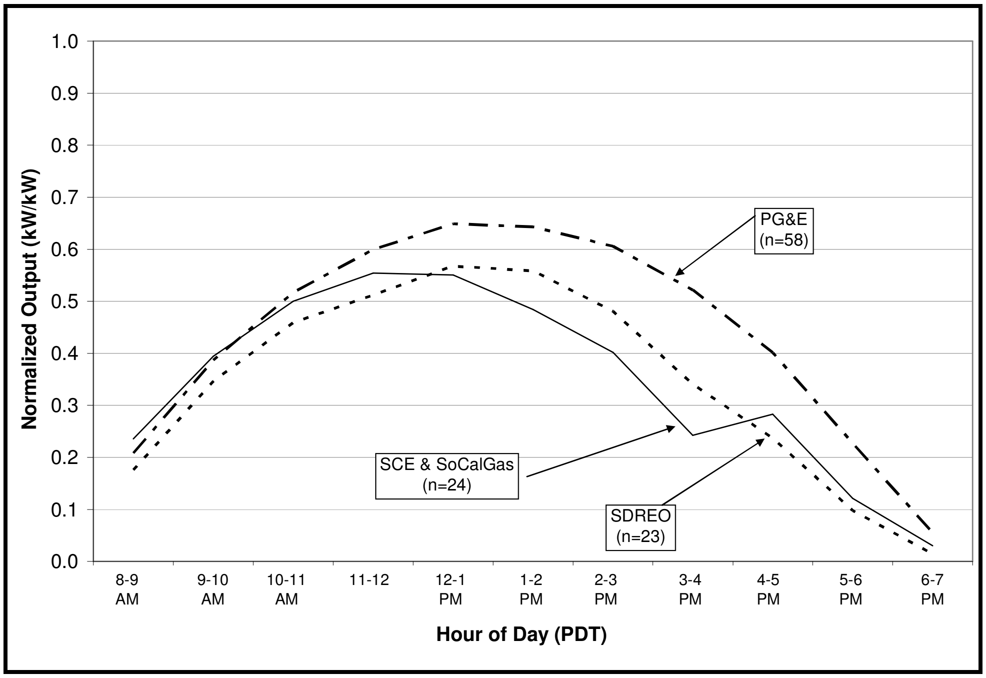
For example, between 3:00 and 4:00 p.m., one system produced approximately 81% of its rebated capacity, while another system produced only 6% of its rebated capacity. The weighted average power production rate was 0.39 kW/kW. Interestingly, on this day the system with the lowest power output during the peak hour is the same system that produced the highest output during each of the hours from 8:00 a.m. to 12:00 p.m. This case illustrates the influence of weather on PV system power output. Solar radiation data from a nearby weather station in Indio, CA suggest that a thunderstorm caused the solar resource available to this system to plummet 76% from just one hour to the next. Also interesting to note in Figure 8-3 is the fact that for each of the ten hours pictured the maximum value corresponds to a system that is either tilted at least 25 degrees from horizontal or that is equipped with a tracking mechanism.

Figure 8-3: 2004 CAISO Peak Day PV Output Profile Summary



The PA-specific generation profiles for the CAISO peak day are presented in Figure 8-4. These profiles of hourly generation output represent weighted averages calculated as the total power output of the metered systems divided by total cumulative rated size of those systems. For each curve in this graphic the total number of metered sites (n) contributing to the generation profile is identified. On the CAISO 2004 system peak day PV systems in northern California outperformed those in southern California. The incidence of inclement weather on this day east of Los Angeles was noted above. Review of weather data from a weather station in San Diego indicates a solar radiation rate of 416 W/m^2 during the hour from 3:00 to 4:00 p.m. Just four days later on September 12, the solar radiation rate during this same hour was 55% higher (644 W/m^2). This case illustrates the regional variability and day-to-day variability exhibited by the solar resource and PV system power output.

Figure 8-4: 2004 CAISO Peak Day PV Output Profiles By PA (September 8)



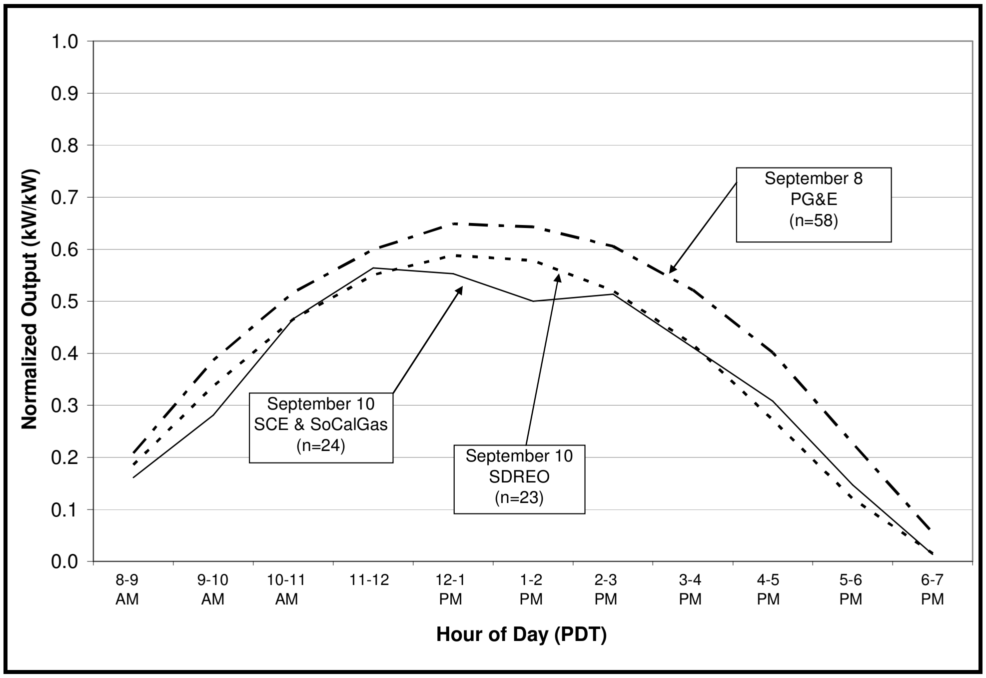
Each individual IOU electric system experienced its own specific annual peak load during a different hour of the year, as summarized in Table 8-4. PG&E experienced its 2004 IOU-specific annual peak load on the same day as the CAISO system peak (September 8), but several hours later. SCE and SDG&E experienced their IOU-specific annual peak loads two days later, on Friday September 10, 2004. All of the IOU-specific annual peak loads occurred later in the day than that of CAISO.

Table 8-4: Characteristics of 2004 IOU-Specific Peaks

Investor-Owned Utility (IOU)	Daily Maximum Temp. (ºF)	Day	Hour of IOU System Peak	IOU-Peak PV Demand Impact (kW/kW)
PG&E	89 ºF	Sept. 8	6-7 p.m.	0.06
SCE	90 ºF	Sept. 10	5-6 p.m.	0.15
SDG&E	82 ºF	Sept. 10	4-5 p.m.	0.27

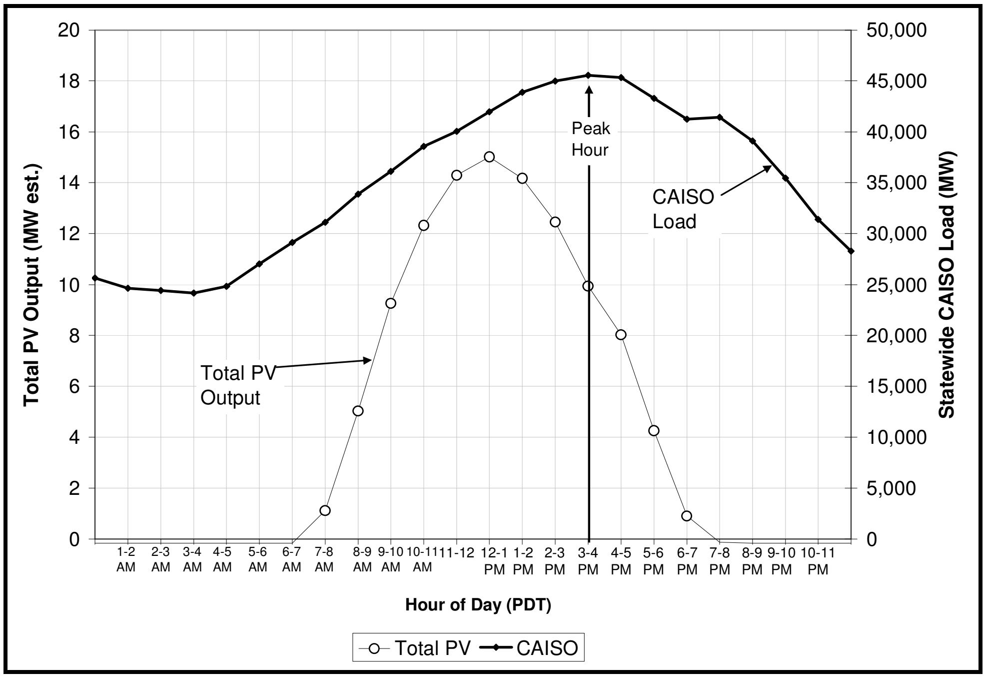
The PA-specific generation profiles for September 8 were presented in Figure 8-4. In Figure 8-5, PA-specific generation profiles are presented for the days on which IOU-specific peaks occurred. The generation profiles in this chart are grouped more closely, which suggests that in Southern California the skies were clearer on the day of the Southern utilities' IOU-specific electrical system peak loads (September 10).

Figure 8-5: 2004 IOU-Specific Peak Day PV Output Profiles By PA



The peak-day profiles of both CAISO system loads and the total of the metered/estimated output of the 235 on-line PV systems are illustrated in Figure 8-6. While PV system power output was substantial on the day of the CAISO system peak, the PV output curve shape is more pointed than the CAISO load shape. After 1 p.m. the output of PV systems began falling, whereas CAISO loads continued to increase for several hours.

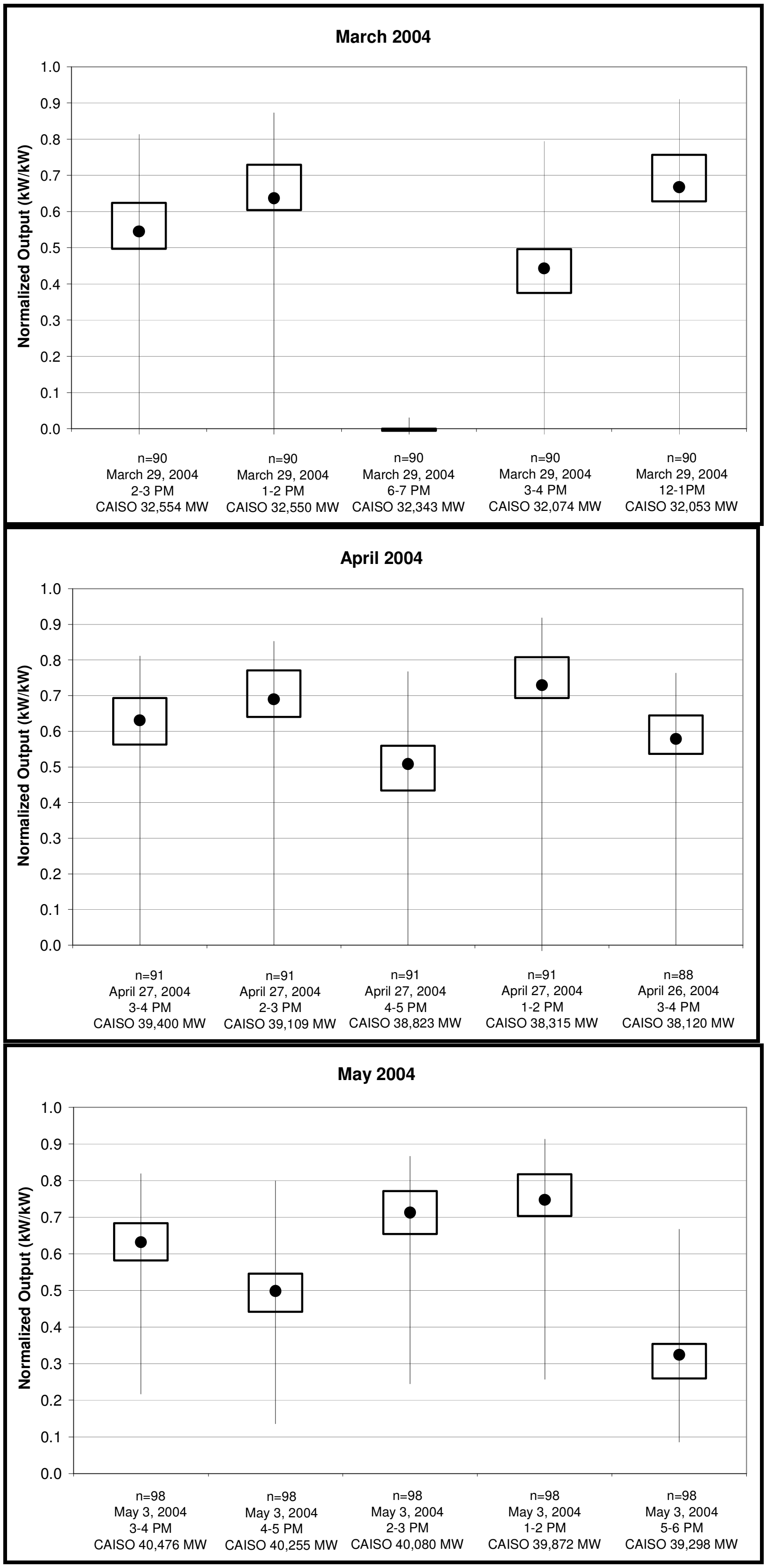
Figure 8-6: 2004 CAISO Peak Day System Loads and Total PV Output



To more completely characterize SGIP demand impacts, normalized hourly output of the metered PV systems during fall, summer, and spring hours coincident with the CAISO maximum loads (i.e., 5 peak hours of each month) are summarized in Figure 8-7 through Figure 8-9.

In these charts each of the five box plots summarizes power output of metered PV systems during one of the five hours during which CAISO maximum loads occurred in each month. The left-most box plot corresponds to the hour when the maximum CAISO load occurred during the month. The remaining four box plots are arranged in order of descending CAISO load. CAISO emergency operating conditions are noted where applicable. Box plots are not provided for winter months because wintertime CAISO loads reached maximum values during evening hours when PV output was near zero. The weighted average values, depicted in these charts with solid black circles, were calculated as the total power output of the metered systems divided by total cumulative size of those systems. Weighted averages such as these were calculated and applied to their respective strata in cases where metered data were unavailable and it was necessary to calculate estimates of PV power output.

Figure 8-7: PV Demand Impact – Spring



Stage 1 Emergency

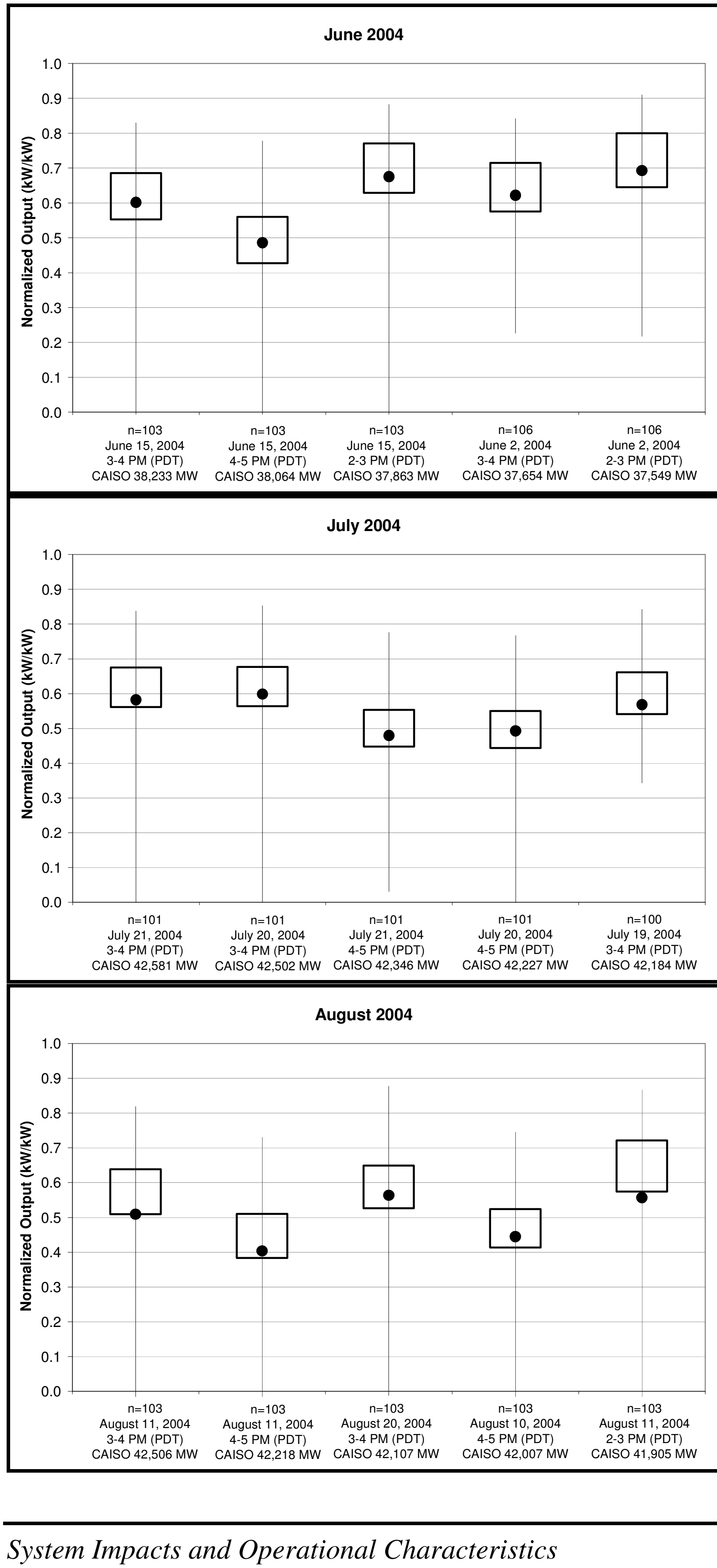
The CAISO declared a Stage 1 Emergency at 1:50 p.m. (PDT). In Southern California temperatures were higher than forecast, and 770 MW of power plants tripped out of service in the morning. Three systems were off-line for maintenance or repair on March 29. An inverter trip took one of these systems off-line for a total of eight days in this timeframe.

In April 2004 CAISO loads reached maximum values during afternoon hours when most PV systems were producing power. In April 2003 CAISO loads reached maximum values during evening hours when PV output was minimal.

The three systems that were off-line in March were back on-line in April. In April no more than two systems were off-line during these five hours.

For these five hours in May 2004, PV output was correlated with hour of day, which suggests relatively clear skies. A single-axis tracking system was responsible for the highest power output rate during the hours from 3:00 to 6:00 p.m. when power output of fixed, horizontal systems was falling more quickly.

Figure 8-8: PV Demand Impact – Summer



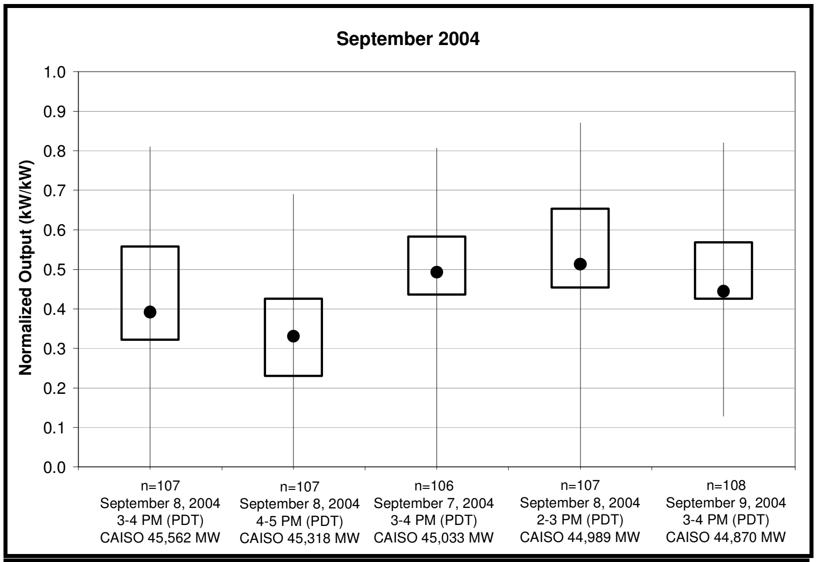
Two PV systems totaling 106 kW were off-line when the CAISO reached its June 2004 peak loads.

Weighted average PV power output was 0.58 kW/kW when the July 2004 CAISO peak load occurred during the hour from 3 p.m. to 4 p.m. This is very similar to the result (0.59 kW/kW) determined for the July 2003 CAISO peak hour (also 3 p.m. to 4 p.m.).

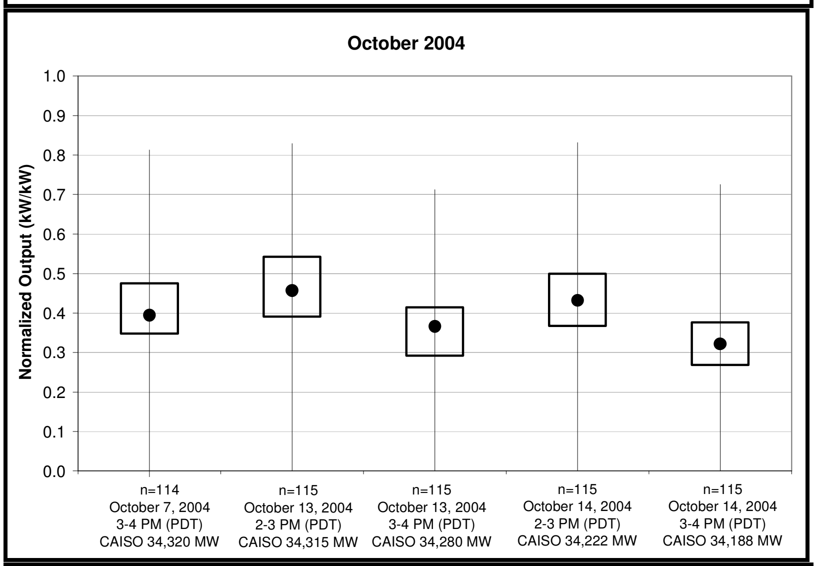
Of all the CAISO peak hours, the tightest grouping of performance occurred on July 19 during the hour from 3:00 to 4:00 p.m.

The weighted average value can be outside of the rectangle when a large system's output is either quite high or quite low. On August 11 from 2:00 to 3:00 p.m. a very large (>750 kW) PV system's output was 0.16 kW/kW due to cloudy skies, which lowered the weighted average substantially. One of the off-line systems on August 11 was off-line due to work being done on the building electrical system.

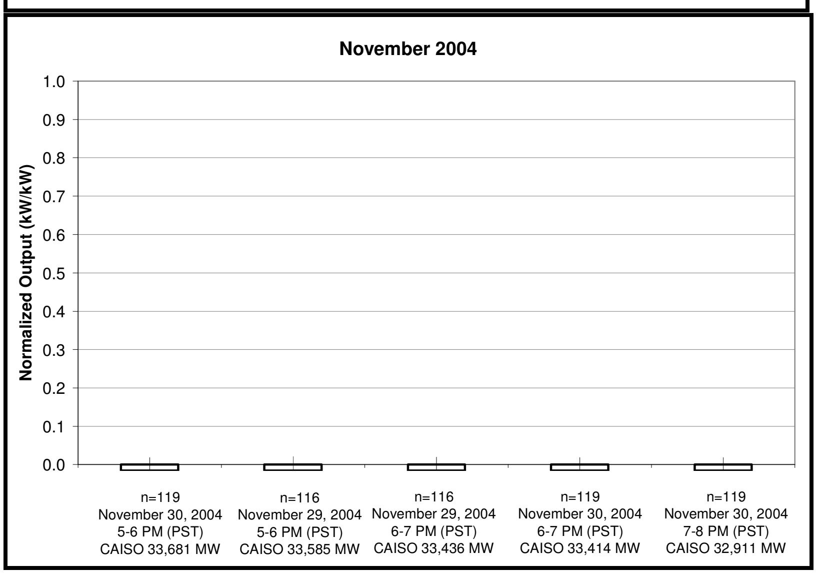
Figure 8-9: PV Demand Impact - Fall



On September 8 during the hour from 3:00 to 4:00 p.m. (PDT) the CAISO reached its annual peak level. During this hour only 60 kW (0.4%) of a total 16 MW of metered PV was off-line for maintenance or repair.



While power output levels were lower than during CAISO peak hours during summer months, the PV systems continued to provide demand impact into mid-Fall during CAISO peak hours. During these five hours no more than 2 PV systems were off-line for maintenance or repair at any one time.



During November 2004 maximum CAISO loads occurred during evening hours. Several systems produced small quantities of power during these hours; however, the weighted average PV output of metered systems was near zero. Some PV systems include isolation transformers that can *consume* small amounts of power at night.

Energy Impact

When metered data were available, they were used directly to calculate energy impacts of PV systems. However, as noted above a substantial portion of total SGIP PV energy production was not captured in interval-metered data. Therefore, energy impacts were estimated in cases where metered data were not available. Metered and estimated energy production (MWh) impact results for Level 1 PV systems are summarized by quarter in Table 8-5.

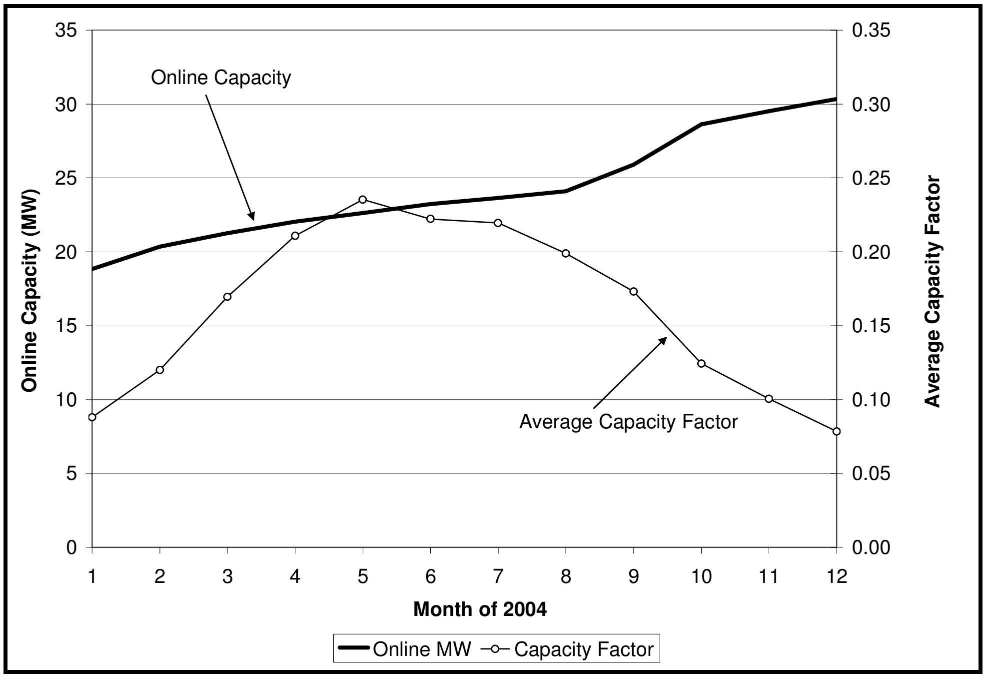
Table 8-5: Energy Impacts of PV in 2004 by Quarter (MWh)

Output Basis	Q1-2004	Q2-2004	Q3-2004	Q4-2004	Total MWh
Metered	3,467	6,984	6,976	4,194	21,620
Estimated	2,145	4,036	3,673	2,360	12,215
Total	**5,612**	**11,020**	**10,649**	**6,553**	**33,835**

The quarter-to-quarter variability exhibited in energy impact results presented in Table 8-5 is largely due to the fact that projects were coming on-line throughout 2004. The project completion trend is summarized in Figure 8-10 (on the left axis). The energy production of the group of metered PV systems varied according to season. In Figure 8-10, normalized energy production by month is illustrated (on the right axis). These values represent the monthly average capacity factor for the on-line PV system capacity.

As expected, normalized energy production levels reach their maximum values in the summer season and decrease towards the winter season as the intensity and duration of incident solar radiation falls off, and with the increased incidence of storms and other weather disturbances which affect the availability of solar radiation on the PV systems. The arithmetic mean of these monthly values is 16%. The annual average load factor for individual systems, or for years other than 2004, will likely be different. Some of the factors underlying these observed PV system energy production results are discussed further in Section 9, Participant Perspectives.

Figure 8-10: PV On-Line Capacity & Average Capacity Factor (2004)



8.4 Level 1 Wind Turbine Systems

The first SGIP wind turbine system to become operational did so by September 1, 2004, although the incentive had not yet been paid as of the end of 2004. Several other wind system projects remain Active but have not yet come on-line. Interval-metered data were not collected from the single operational wind turbine system during 2004. Its energy and demand impacts were estimated. Table 8-6 and Table 8-7 present these estimated demand and energy impacts. The estimates were based on wind speed data from two nearby weather stations. The available 10-meter wind speeds were scaled up to the actual hub height of the rebated wind turbine. The reported absence of demand impact is attributable to low wind speeds measured at the weather stations on the day of the 2004 CAISO peak.

Table 8-6: Impact of Level 1 Wind Turbines Coincident with 2004 CAISO Peak

Output Basis	On-Line Systems (n)	On-Line Capacity (kW)	Peak Demand Impact (kW_P)
Metered	0	0	0
Estimated	1	950	0
Total	**1**	**950**	**0**

Table 8-7: Energy Impact of Level 1 Wind Turbines in 2004 by Quarter (MWh)

Output Basis	Q1-2004	Q2-2004	Q3-2004	Q4-2004	Total MWh
Metered	0	0	0	0	0
Estimated	0	0	0	339	339
Total	**0**	**0**	**0**	**339**	**339**

8.5 Level 1 & 2 Fuel Cells

As of the end of 2004, no Level 1 fuel cells (renewable fuel) were operational, although two such projects were in various stages of development. One Level 2 fuel cell project was installed and on-line for the entire year in 2004, while a second unit came on-line in June. An average operating capacity factor of 91% is indicated by the limited quantity of available metered data. This average value was used to estimate demand and energy impacts of the on-line fuel cell systems during periods when metered data were not available. Estimated 2004 peak demand impacts on the CAISO from the on-line Level 2 fuel cell projects are summarized in Table 8-8.

Table 8-8: Impact of Level 2 Fuel Cells Coincident with 2004 CAISO Peak

Basis	On-Line Systems (n)	On-Line Capacity (kW)	Peak Demand Impact (kW_P)	ISO Peak Ratio ($kW_P/kW_{Rebated}$)
Metered	1	200	196	0.98
Estimated	1	600	548	0.91
Total	**2**	**800**	**744**	**0.93**

The distribution of Level 2 fuel cell energy impact by quarter is summarized in Table 8-9.

Table 8-9: Energy Impact of Level 2 Fuel Cells in 2004 by Quarter (MWh)

Output Basis	Q1-2004	Q2-2004	Q3-2004	Q4-2004	Total MWh
Metered	422	403	356	349	1,530
Estimated	0	286	1,260	1,209	2,755
Total	**422**	**689**	**1,616**	**1,559**	**4,286**

8.6 Level 3/3-N/3-R: Microturbines, IC Engines, and Small Gas Turbines

Consistent with the other technologies, data from metered projects were used to estimate impacts of un-metered internal combustion engines, microturbines, and small gas turbines.

Available metered data were used to calculate ratios representing average power output per unit of rebated system capacity. For periods when no metered data were available, estimates of power output were calculated as:

$$EN\hat{G}O_{sdh} = \left(S_s\right)_{Unmetered} \times \left(\frac{\sum ENGO_{sdh}}{\sum S_s}\right)_{Metered}$$

Where:

$EN\hat{G}O_{sdh}$ = Predicted net generator output for system *s* on day *d* during hour *h*

Units: kWh

Source: Calculated

S_s = System size for system *s*

Units: kW

Source: SGIP Tracking System

$ENGO_{sdh}$ = Metered net generator output for system *s* on day *d* during hour *h*

Units: kWh

Source: Net Generator Output Meters

Some SGIP projects satisfy the program's heat recovery requirements by providing recovered heat to an absorption or adsorption chiller that enables elimination or unloading of electric-driven cooling capacity. Indirect electric demand impact yielded by elimination or unloading of electric chillers is not included in the SGIP impact evaluation results reported in the annual impact evaluation reports.

The issue of so called 'secondary' or indirect electric impact of cooling or other electric process heating equipment will be addressed in detail as part of the preliminary cost-effectiveness evaluation, findings of which are scheduled to be reported in May 2005. In the cost-effectiveness evaluation, the assessment of equipment not covered directly by the SGIP will include incremental electric impact as well as incremental project cost. Both will be governed by baseline assumptions underlying the analysis. The issue of baseline assumptions was discussed in detail in Section 8 of the previous impact evaluation report that presented impacts of the program occurring during 2003.

Demand Impact Coincident with CAISO Peak

On September 8, the day of CASIO system peak demand, there were 147 engines and turbines installed and on-line under the SGIP. Interval-metered data were available for 72 of these Level 3/3-N/3-R systems. Resulting estimates of peak demand impact on the CAISO are summarized in Table 8-10. The estimated demand impact corresponds to 0.58 kW per 1.00 kW of installed system size (basis: rebated capacity). The total program-level system peak demand impact for incentive Level 3/3-N/3-R engines and turbines is estimated at 44,115 kW (i.e., approx. 44 MW).

Table 8-10: Impact of Level 3/3-N/3-R Systems Coincident with 2004 CAISO Peak

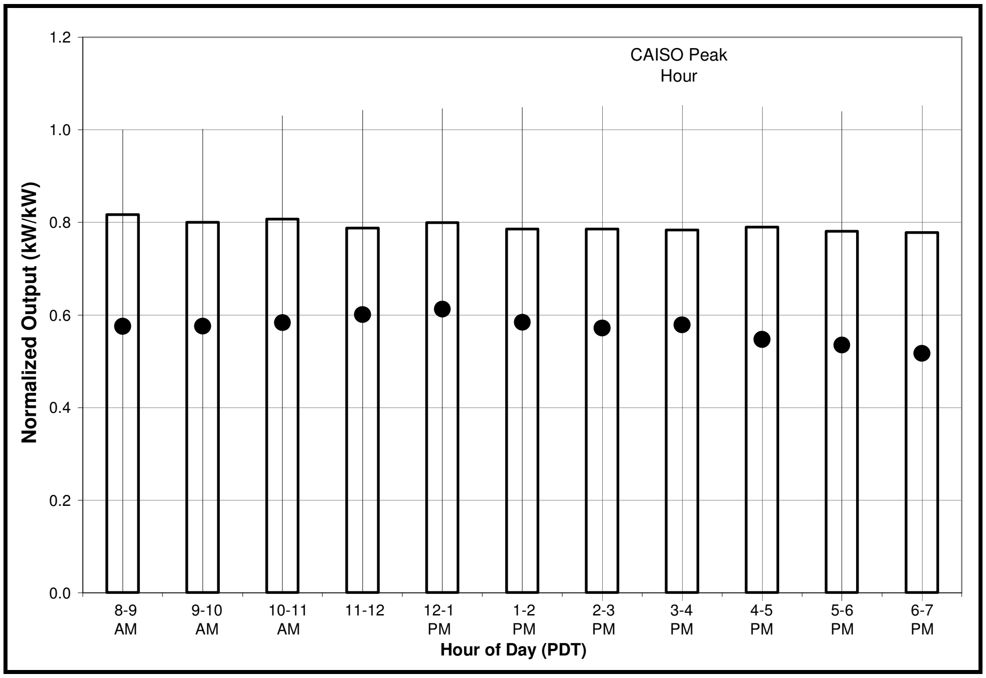
Basis	On-Line Systems (n)	On-Line Capacity (kW)	Peak Demand Impact (kW_P)
Metered	74	34,900	20,198
Estimated	76	41,030	23,917
Total	**150**	**75,930**	**44,115**

The peak-day operating characteristics of the 74 engine and turbine projects for which peak-day interval-metered data were available are summarized in the box plot of Figure 8-11. System sizes were used to normalize power output values prior to plotting summary statistics of electric output profiles for individual projects. The normalized values represent power output per unit of system size. Treatment in this manner enables direct comparison of the power output of systems of varying sizes.

The boxes represent ranges within which 75 percent of project-specific values lie. The vertical lines represent the range of project-specific values (i.e., maximum and minimum normalized output). The weighted averages depicted in this graphic with solid black circles were calculated as the total power output of the 74 systems divided by total cumulative capacity of those systems. These values were used to estimate output of Level 3/3-N/3-R projects in cases where metered data were unavailable. Numerous systems were idle on this CAISO peak day, which explains why the lower edge of the 25th to 75th percentile rectangles are positioned at 0 kW/kW.

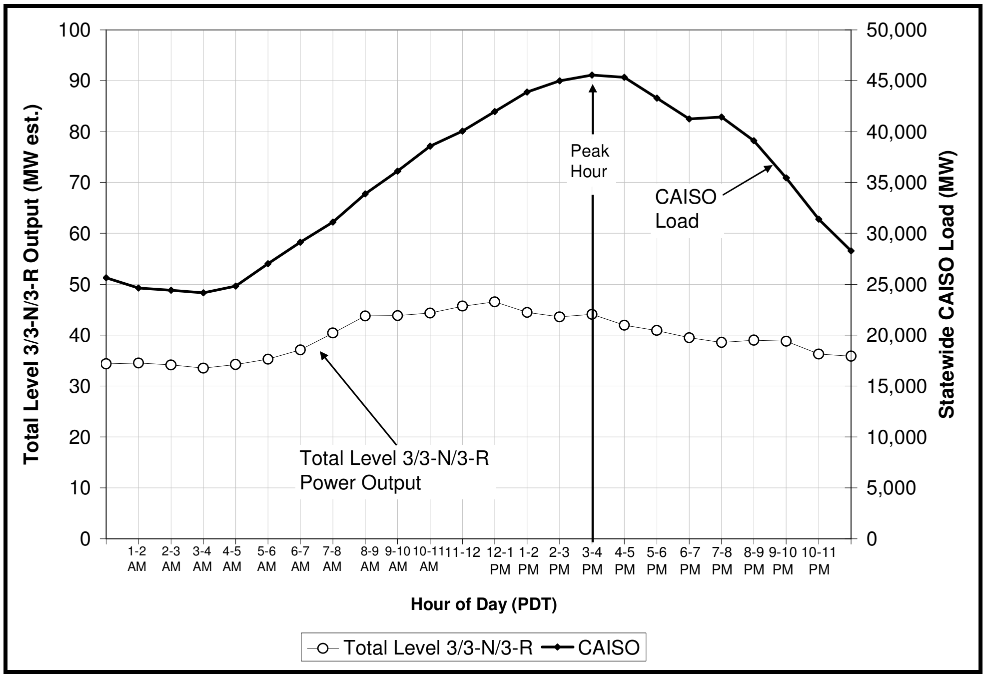
During the hour from 3 p.m. to 4 p.m., 19 of the 74 (26%) metered systems were idle. For the 11 hours pictured in Figure 8-11 the portion of idle systems ranged from 26% to 32% (23 of 73 systems during the hour from 6:00 to 7:00 p.m.). Several internal combustion engine projects are responsible for all of the power output rates exceeding 1.0 kW/kW by a small amount. One Level 3-R project is included among the metered projects whose performance is depicted in Figure 8-11. This system was generating power during 10 of the 11 hours pictured.

Figure 8-11: CAISO Peak Day Level 3/3-N/3-R Output Profile Summary



The peak-day profiles of CAISO system loads and the total of the metered/estimated output of the 150 on-line Level 3/3-N/3-R systems are illustrated in Figure 8-12. The shape of the output curve for engines and turbines aligns well with the CAISO system peak from 3 p.m. to 4 p.m., and the two curves maintain a similar relationship during both diurnal shoulder periods (before and after the peak).

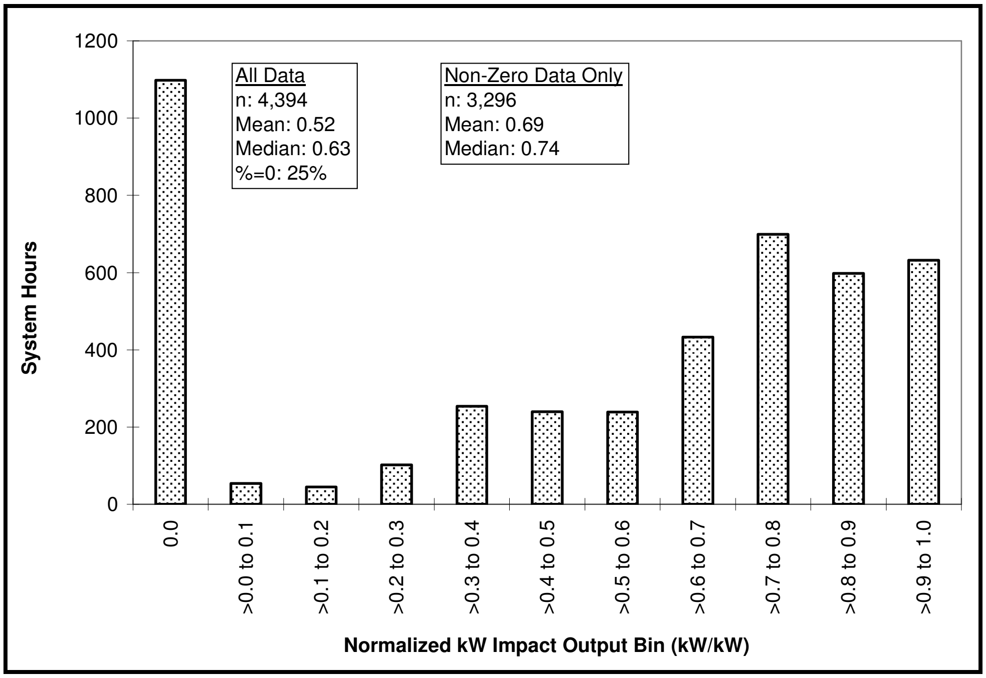
Figure 8-12: CAISO 2004 Peak Day Load & Coincident Total Level 3/3-N/3-R Generation Output



To more completely characterize SGIP demand impacts, normalized hourly output of the metered Level 3/3-N/3-R systems during 2004 coincident with the CAISO maximum loads (i.e., based on the 5 peak hours of each month) are summarized in Figure 8-13. Each "System Hour" represents a 60-minute period during which a system was "on-line". In some instances systems were on-line but not operational. Such idle systems influence the weighted average demand impact of the SGIP systems.

Whereas for PV both intra- and inter-day variability were significant, for Level 3/3-N/3-R systems it was more meaningful to consider all 60 CAISO-maximum load hours as a single group. These 60 hours correspond to a total of 4,394 system hours (i.e., the average number of "on-line" but not necessarily operational systems was 73). As discussed previously, on-line capacity increased steadily throughout 2004. For this group, normalized kW output of the monitored systems averaged 0.52 kW of power output per kW of rebated system size during the top 5 peak load hours of each month over the CY04 period of this assessment. This annual average result is similar to the weighted average demand impact of metered systems during the single hour of the CAISO annual peak (0.58 kW/kW).

Figure 8-13: Demand Impact – Level 3/3-N/3-R
Basis: Five Hours each Month when CAISO Loads Reach Maximum Levels



The idle units (0.0 kW/kW normalized output) play an important role in reducing the average output of all rebated units during hours when CAISO loads reach their maximum values. The average output of operational projects (0.69 kW/kW) is 33% higher than the average for the entire group (including idle systems). Several characteristics of the idle-system hours include:

- Many rebated systems comprise multiple generating units. For instance, for a system comprising two units, normalized output equal to 0.5 kW/kW could represent full-load operation of one unit only, or half-load operation of both units. In many instances electric metering captures output of all rebated units, thus limiting ability to infer operational practices directly from the data.
- Cogeneration systems may be operated in a “load following” mode. Depending on the size of the cogeneration system relative to the magnitude and timing of facility loads, this factor could account for some of the system hours corresponding to reduced normalized output levels. The influence of these factors on energy production is discussed in the following section.

Energy Impact

When metered data were available, they were used directly to calculate energy impacts of Level 3/3-N/3-R systems. Energy impacts were estimated in cases where metered data were not available. The resulting distribution of energy impacts by quarter is summarized in Table

8-11.[2] The variability in energy production observed across quarters is partially attributable to systems coming on-line throughout 2004. Fuel price variability is another factor influencing energy impact. The issue of fuel price versus electricity price (i.e., "spark gap") is discussed in more detail in Section 9, Participant Perspectives.

Table 8-11: 2004 Energy Impacts of Level 3/3-N/3-R Systems by Quarter (MWh)

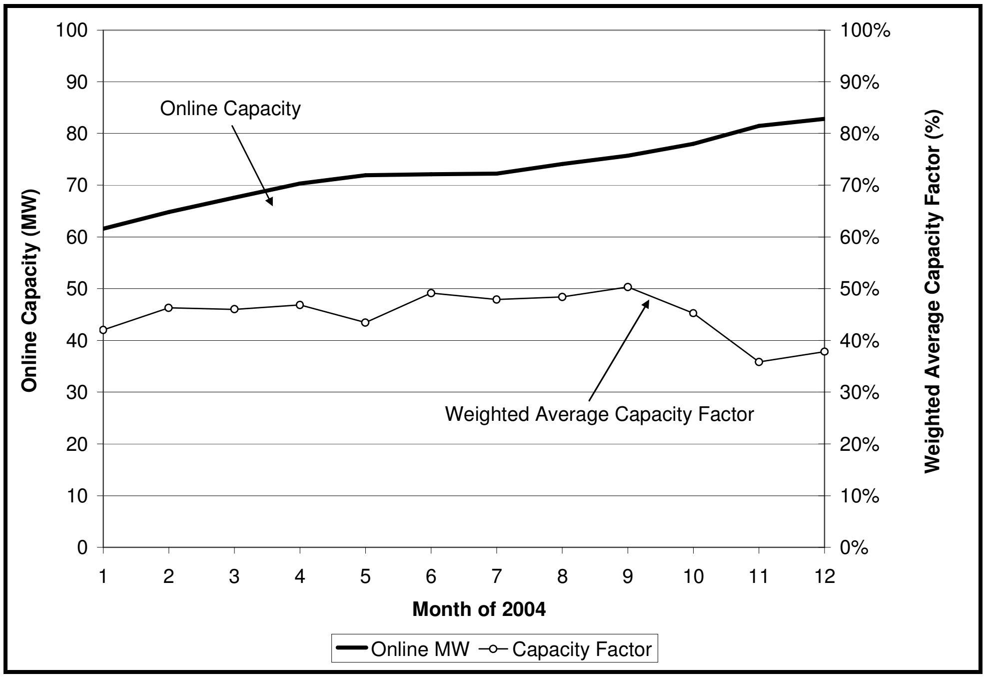
Basis	Q1-2004	Q2-2004	Q3-2004	Q4-2004	Total MWh
Metered	40,777	46,906	49,633	35,613	172,929
Estimated	22,499	25,582	30,223	34,960	113,264
Total	**63,276**	**72,488**	**79,856**	**70,574**	**286,193**

The project completion trend for Level 3/3-N/3-R systems is summarized in Figure 8-14 along with monthly average capacity factor. Whereas for PV systems the pronounced seasonal variability of monthly average capacity factor illustrated in Figure 8-10 was expected, the capacity factor of engines and turbines is influenced by fundamentally different factors. PV system power output is primarily governed by weather, and PV systems in the program are eligible for net-metering tariffs that enable them to produce more power than is consumed by the facility during certain hours.

Engine and turbine power output is primarily governed by on/off switches and the on-site demand for thermal energy, and is generally required to be controlled to a level such that substantial quantities of power are not exported to the grid. Depending on the relative size of the engine or microturbine system, when facility power requirements are low the power output of the DG system might need to be throttled down to prevent export of power to the grid. Consequently, monthly average capacity factor may be strongly influenced by facility operating hours (i.e., 1-, 2-, or 3-shift). The capacity factor data presented in Figure 8-14 are provided for summary purposes only. Because additional metered systems were being added periodically throughout the year, and the number of complete-year datasets is small, it is not possible to draw any sweeping conclusions from these summary data. They do provide a meaningful reference point for comparison to capacity factors for other technologies, however.

[2] The ratio of metered to estimated energy impacts is higher than the ratio of metered to estimated demand impact because monthly fuel usage and monthly generator electric energy production data were used in the assessment of energy impact. The analysis of electric demand impact was limited to systems where interval-metered electric power output data were available.

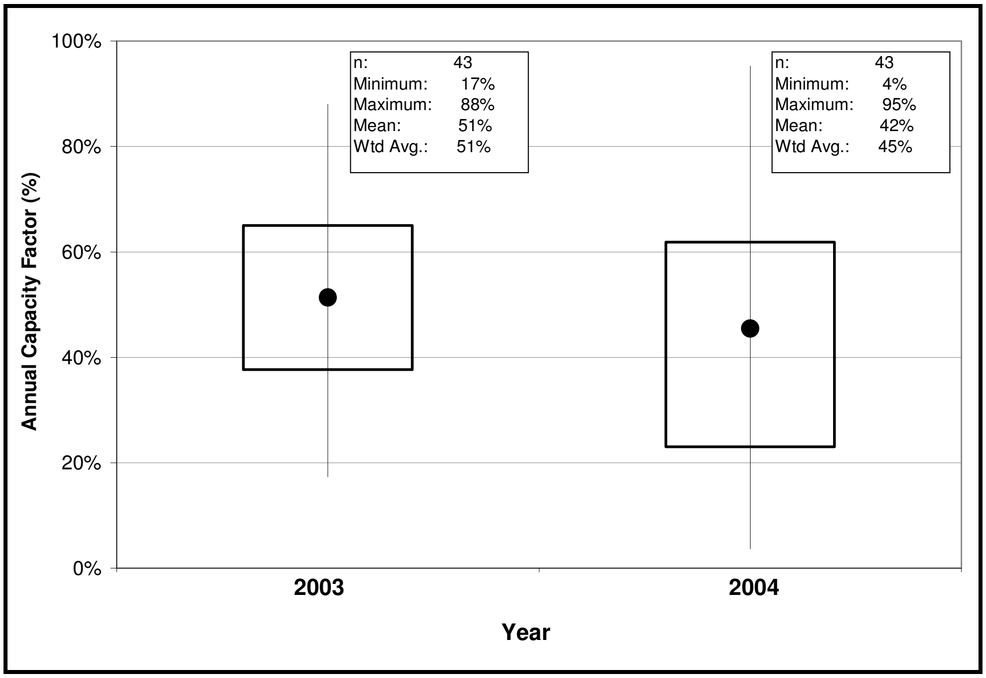
Figure 8-14: Level 3/3-N/3-R On-Line MW & Average Capacity Factor (2004)



Generator electric energy production data for 2003 and 2004 are available for a subset of the 165 Level 3/3-N/3-R projects that had come on-line as of the end of 2004. For these systems a comparison of 2003 capacity factors versus 2004 capacity factors is depicted graphically in Figure 8-15. The analysis was limited to those projects where at least six months of data were available for each of the years. These data indicate a downward trend in average capacity factor and an upward trend in inter-site capacity factor variability. Owners of a sample of these systems were interviewed as part of this impact evaluation to gather information concerning explanations for observed performance and expectations for future performance. Results of these interviews are summarized in Section 9, Participant Perspectives.

In 2003 and 2004 the same two projects accounted for the two highest capacity factors. One was a 1,000 kW engine system, while the other was a 120 kW microturbine system. Both systems operated nearly continuously and were fueled with natural gas. In 2004 two systems had a capacity factor less than 10%. Both of these systems had capacity factors exceeding 30% in 2003. In 2003 the lowest capacity factor was 17%; this engine system's capacity factor fell to 13% in 2004.

Figure 8-15: Level 3/3-N/3-R Capacity Factor Trend



8.7 Review of Useful Thermal Energy and System Efficiency

Level 2 fuel cells and Level 3/3-N cogeneration systems are subject to certain heat recovery and system efficiency requirements during the implementation stage of the SGIP. A variety of means are used to recover heat for useful purposes, and to apply that heat to provide various forms of heating and cooling services. The end-uses served by recovered useful thermal energy are summarized in Table 8-12, which includes projects that had come on-line through December 2004.

Table 8-12: End-Uses Served by Level 2/3/3-N Recovered Useful Thermal Energy (Total n and kW as of 12/31/2004)

End Use Application	On-Line Systems (n)	On-Line Capacity (kW)
Heating Only	96	39,938
Heating & Cooling	38	21,726
Cooling Only	18	15,261
Total	**156**	**76,925**

To assess actual heat recovery and system efficiency performance, useful heat recovery will be monitored. Availability of these data for 2004 is summarized in Table 8-13, which provides the number and capacities of cogeneration projects for which useful thermal energy data for CY04 were available. In some cases, availability of CY04 data was not sufficient to estimate PUC 218.5 thermal energy proportions or efficiencies due to their annual basis. These sites with insufficient data were not included in Table 8-13 or in the subsequent summaries of system efficiency results.

Table 8-13: Level 2/3/3-N Useful Thermal Energy Data Availability (CY04)

End Use	On-Line Systems (n)	On-Line Capacity (kW)
Heating Only	19	7,874
Heating & Cooling	7	4,520
Cooling Only	6	4,063
Total	**32**	**16,457**

Overall Cogeneration System Efficiency Actually Observed

Level 2 fuel cell and Level 3/3-N engine/turbine cogeneration system designs are required to demonstrate (on paper through engineering design documentation) achievement of the required PUC 218.5 minimum proportion and efficiency presented in Table 8-14.

Table 8-14: Program Required PUC 218.5 Minimum Performance

Element	Definition	Minimum Requirement
218.5 (a)	Proportion of facilities' total annual energy output in the form of useful heat	5.0%
218.5 (b)	Overall system efficiency (50% credit for useful heat)	42.5%

Available metered thermal data collected from on-line cogeneration projects were used to calculate overall system efficiency incorporating both electricity produced as well as useful heat recovered. Results are summarized in Table 8-15.

Table 8-15: Level 3/3-N Cogeneration System Efficiencies (n=31)

Summary Statistic	218.5 (a) proportion	218.5 (b) Efficiency	Overall Plant Efficiency
Min	5%	19%	22%
Max	71%	54%	82%
Median	46%	36%	46%
Mean	44%	37%	49%
Std Dev	17%	7%	14%
Coefficient of Variation	0.4	0.2	0.3

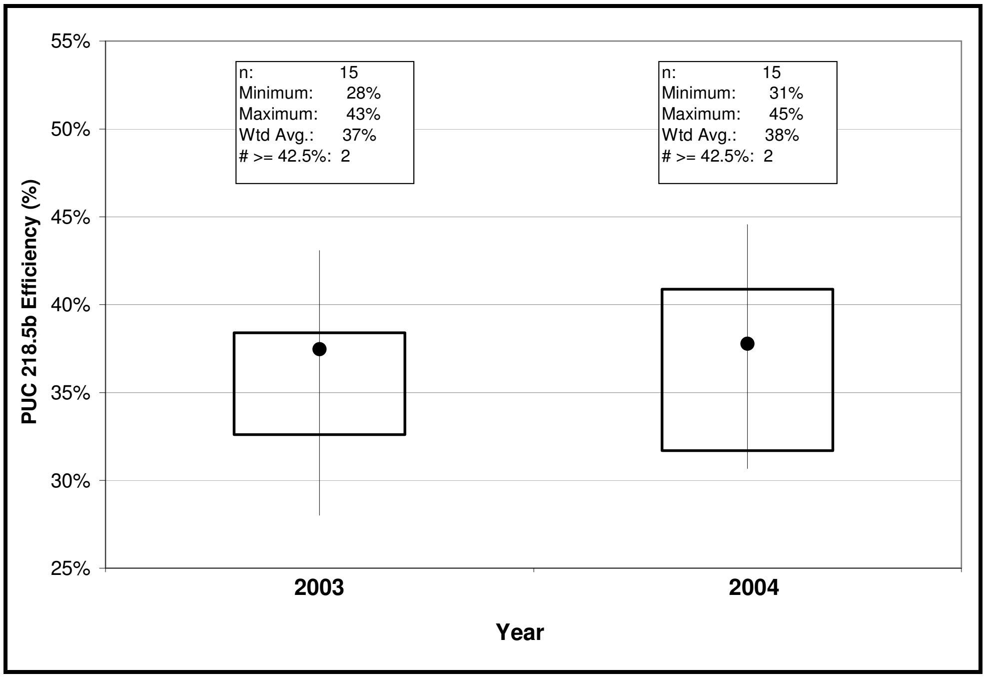
At least 10 months of operating data were available for 21 of the 31 systems. In 10 other cases at least six months of data were available for either the first half or the second half of 2004. While the basis of the PUC 218.5 proportions and efficiencies are annual, when at least six months of data from several seasons are available, the calculated results were annualized and thus were considered representative of what could be expected on an annual basis.

Metered data collected to date suggest that nine of the 31 monitored Level 3/3-N projects achieved the 218.5 (b) overall system efficiency target of 42.5%. Four of these nine systems utilize recovered heat for both heating and cooling. Cogeneration systems utilizing recovered heat in this manner account for 23% of the 31 systems examined, but 44% of the nine systems achieving the prescribed PUC 218.5 (b) efficiency. Four of the remaining five systems meeting the 218.5 (b) requirement utilized recovered heat for heating only, while one utilized recovered heat for cooling only.

The limited quantities of cogeneration system data available for this impact analysis suggest the possibility of systematic negative variance between planned system efficiencies and actual system efficiencies. However, collection and analysis of additional data is required before definitive conclusions can be drawn. Data were available for one fuel cell project, which satisfied the requirements of PUC 218.5 (a) and achieved a PUC 218.5 (b) system efficiency exceeding 50%.

Cogeneration system PUC 218.5 (b) system efficiency data for 2003 and 2004 are available for 15 of the 31 projects. For these systems a comparison of 2003 efficiencies versus 2004 efficiencies is depicted graphically in Figure 8-16. These data indicate a slight upward trend in PUC 218.5 (b) system efficiencies. Owners of a sample of these systems were interviewed as part of this impact evaluation to gather information concerning explanations for observed performance and expectations for future performance. Results of these interviews are summarized in Section 9, Participant Perspectives.

Figure 8-16: Level 3/3-N Cogeneration System PUC 218.5 (b) Trend



Electrical Conversion Efficiency Actually Observed

Results of an analysis of cogeneration system electrical conversion efficiencies are presented in Table 8-16. Gross electric generator output data and engine/turbine fuel usage data were combined to develop a calculation of engine/turbine electric conversion efficiency. In the case of reciprocating engines (ICE), actual electrical conversion efficiencies of approximately 30% are typical for monitored SGIP cogeneration systems. This typical result is below electrical conversion efficiencies normally found in published technical specifications of engine-genset manufacturers. These nominal nameplate electrical generating efficiencies published by manufacturers generally exceed 30%, and sometimes exceed 35%.

Table 8-16: Level 3/3-N Electrical Conversion Efficiency[3]

Summary Statistic	Internal Combustion Engines (ICE)	Microturbines (MT)
n	36	17
Min	20%	16%
Max	38%	27%
Median	30%	23%
Mean	30%	22%
Std Dev	4%	3%

Observed electrical efficiencies for microturbines were lower than those for reciprocating engines, as expected. The median efficiency actually observed was 23%. This is lower than nominal microturbine efficiencies typically published by manufacturers. For purposes of comparison, the observed electrical conversion efficiencies are presented in Table 8-17 with representative nominal efficiencies. In the context of PUC 218.5 (b) efficiency calculations, these variances are relatively more significant than those on the useful recovered heat side of the equation because only 50% credit is given to the recovered heat in the 218.5 (b) efficiency equation. These factors are discussed in more detail in the following section.

Table 8-17: Representative Nominal Versus Observed Gross Electrical Conversion Efficiencies

Combustion Technology	Representative Nominal Efficiency (%, LHV)	Median Observed Efficiency (%, LHV)
Microturbine (MT)	28%	23%
Internal Combustion Engine (ICE)	34%	30%

Useful Heat Recovery Actually Observed

To enable direct comparison of systems of different sizes the monthly average heat recovery raw data were normalized with respect to net generator electric energy output. Normalized actual useful heat recovery rates are therefore expressed in terms of kBtu of useful recovered heat per kWh of net generator electric energy production. The recovered useful thermal

[3] The electrical conversion efficiencies are calculated as the ratio of gross electric generator output to *lower heating value* of fuel content after converting both components to an identical unit basis. Utility companies refer to natural gas energy content in terms of higher heating value (HHV), which includes the heat that could be recovered if products of combustion were allowed to condense. Engine manufacturers refer to natural gas energy content in terms of lower heating value (LHV), which is based on products of combustion remaining in a gaseous or vapor state.

energy data for Level 3/3-N cogeneration systems are summarized in Table 8-18. For the 31 systems where 2004 data were available for this analysis, substantial variability among systems was observed in the normalized measure of monthly average heat recovery rate. This variability is reflected in the incidence of several projects with very minimal heat recovery, as well as the considerable variability (i.e., 2 to 5 kBtu/kWh) observed for the projects where appreciable quantities of useful heat were recovered.

Table 8-18: Actual Useful Heat Recovery Rates (n = 31)

Summary Statistic	Value (kBtu/kWh)
Min	0.2
Max	8.5
Median	2.9
Mean	3.3
Std Dev	2.1

In general, the actual useful heat recovery rates observed in 2004 were less than projected by engineering calculations completed during the design stage of cogeneration system project development. The negative variance is due to numerous factors, including: design problems, operational problems, unanticipated operating conditions, and system or component reliability problems. Information about these problems was collected as part of the participant perspectives assessment presented as Section 9 of this report.

Finally, it must be emphasized that the quantity of useful recovered heat data is very modest. While the total capacity of operational cogeneration systems approached 83 MW at the end of 2004, this analysis included useful recovered heat data for projects totaling just over 17 MW. In addition, for some of these projects less than a complete year's worth of data were available. This monitored group does not represent a statistical sample; rather, it could best be characterized as a monitored group of cogeneration systems for which useful recovered heat data were available. While results presented in this report for 2004 are suggestive of systematic deviation between planned system efficiency and actual system efficiency, current data availability constraints preclude the drawing of definitive conclusions at this time.

9

Participant Perspectives

9.1 Introduction and Objectives

This section presents the results of interviews with the owners of a sample of the on-line SGIP systems. The interviews were conducted to collect information on system owners' opinions about their systems' performance, maintenance activities and costs, and satisfaction with various aspects of system operations.

The following five steps were taken to conduct this part of the evaluation. First, the main issues to be researched were identified and reviewed with the SGIP Working Group. Second, interview questions were designed to collect the necessary data. Third, a sample of on-line projects was selected. Fourth, telephone interviews were conducted with the primary contact for each of the sampled projects. Finally, the responses were compiled and analyzed.

9.2 Sample Design and Respondent Characteristics

Sample Design

The sample was designed to include owners of on-line projects evaluated for this fourth-year impact evaluation who had not been interviewed during the most recent SGIP process evaluation. The complete set of cogeneration sites from the third-year impact analysis was also included to provide a basis of comparison across time for these sites. Representation across Program Administrators and technologies was also considered.

PV Sites

At the end of CY04, 200 PV systems had been on-line for at least six months. Substantial quantities of metered data were available for only a portion (roughly 100) of these. To solicit input regarding actual system performance, the examination was limited to this subset of 100 sites that had substantial operating history and available metered data. From this subset of projects, 25 sites with system owners who had been interviewed recently were removed. From the resulting 75 sites, a random sample of 50 sites was targeted for interviews.

Cogeneration Sites

The following approach for sampling cogeneration sites was used. First, sites that were operational and for which thermal heat data had been received at some point in 2004 were selected. From this subset, sites with system owners who had been interviewed recently were removed. All cogeneration sites from the 2003 impact analysis were then added to the sample. Finally, the sample was augmented with sites for which at least six months of ENGO data but no heat data were available. This produced a potential sample of 87 cogeneration systems.

The completed sample consists of 47 Level 3-N and 3-R cogeneration and 45 Level 1 PV system interviews. Note that a single interview may represent multiple project sites or systems. Table 9-1 presents the completed sample by Program Administrator and technology.

Table 9-1: Completed Draft Interview Sample

Program Administrator	PV	Cogeneration			Total
		ICN	MTN	MTR	
PG&E	27	12	5	0	44
SCE	1	4	1	1	7
SoCalGas	9	8	4	0	21
SDREO	8	4	6	2	20
Total	***45***	***28***	***16***	***3***	***92***

While the targeted number of completed interviews (50 each for PV and cogeneration projects) was not reached, the results are very close and sufficient information was collected to complete the evaluation.

Sample Characteristics

In addition to Program Administrator and technology type, other system characteristics of the sample, including the number of idle days and the actual capacity factor based on 2004 metered data, were calculated for this analysis. These results are presented in Table 9-2 and in Table 9-4 later in this section.

Alternative Ownership Arrangements

Two principal ownership arrangements are typically observed among systems installed through the SGIP. In most cases, the host customer owns the equipment and the SGIP applicant of record (if different than the host customer) is a vendor of project development and/or management services. In other cases, the SGIP applicant of record is a vendor that, in addition to providing project development and/or management services, also owns and operates the system. For SGIP PV projects, the risk-bearing party is the host customer in all cases. For SGIP cogeneration projects, the host customer is the risk-bearing party for roughly 85% of the projects (or 80% of installed kW capacity), and the third-party applicant is such for the remainder of these projects.

The variety of alternative ownership arrangements has important ramifications where SGIP participant perspectives of system value, performance, and operations/maintenance are concerned. The focus of this current examination of SGIP participant perspectives is on stakeholders with the greatest financial interest in individual systems after they enter normal operations (i.e., the main risk-bearing party). Depending on site-specific project arrangements, the key contact could be either the SGIP host customer or the third-party SGIP applicant. In the case of PV, the survey was limited to host customers. For cogeneration sites, both host customers and third-party applicants were interviewed, depending on their specific project risk-bearing status.

9.3 Data Collection

Telephone interviews were conducted during March 2005. The survey instrument used to guide the interviews is included as Appendix B. The survey instruments were customized with site-specific actual performance information prior to completion of the survey. System performance information was obtained from two sources: 1) metered data from operational projects, and 2) Waste Heat Utilization Worksheets completed prior to DG system construction in the course of verifying eligibility for the SGIP incentive.[1]

9.4 Interview Results and Discussion

System Owner Views on PV System Performance

As stated above, interviews were completed with 45 PV system owners. These 45 interviews represent 52 SGIP PV systems. Results from these interviews are summarized below.

Opinions on System Availability

Respondents whose systems were not producing power for one or more days were asked to comment on the event. Of the 45 respondents, eight had experienced at least one day with no energy production. As explained above, these dates were calculated by the program

[1] Heat monitoring data were available for only 17 of the 87 potential cogeneration systems in the sample. The information from the Waste Heat Utilization Worksheets was available for only 30 of the systems in the potential sample.

evaluator based on metered data received for CY2004. During the interviews, respondents were given the dates their system was not producing and asked to comment.

The eight respondents with idle days had the following comments regarding why their systems had not produced energy.

- Two respondents with idle days reported that their systems had to be shut down to allow the electric utility company to do some repair work on their lines.
- Three respondents reported they did not know why their systems had been idle. One of these respondents speculated that he might have shut it down to do some electrical work.
- One respondent with one idle day reported that he thought it was just due to rainy and foggy weather.[2]
- One respondent, who had idle days in five separate months during CY2004, reported he remembered start-up problems in January 2004 that required changing software in the inverter. He remembered days during that month when the system was not producing. However, he did not know what might have caused the idle days in the other months. Follow up with the system installer and ENGO data provider revealed that the other days with little or no energy production were due to poor weather.
- One respondent with idle days in January, February and December of 2004 reported a reason for the days in January and February but did not know about the days in December. He explained that once a month a backup generator test is conducted which involves cutting power to the building. It was discovered that during these tests the PV inverter shut down. The problem was resolved in March 2004 by installing a capacitor in the inverter so it would not shut down.

<u>Opinions on System Performance</u>

As described in Section 9.2 above and summarized in Table 9-2 below, annualized capacity factors were calculated by the program evaluator for all PV systems in the sample, based on available 2004 metered data.

[2] CIMIS weather data indicate that weather conditions were indeed poor for solar that day.

Table 9-2: Performance Characteristics for Sampled PV Systems vs. All SGIP PV Systems

Item	Value (n = number of sites)
Program total funded capacity 2003-2004 (kW)*	31,820 (n = 286)
Sample capacity (kW)	7,090 (n = 52)
Program average system size (kW)*	111 (n = 286)
Sampled average system size (kW)	136 (n = 52)
Actual capacity factor for sample	17% (n = 52)
Number of days with no energy production during 2004 in sample	1.4 (n = 52)

*Based on all PV systems the received SGIP funding in 2003 and 2004.

The majority of the system annual capacity factor results for the sample fell within the range of 14.5 percent to 18.5% (i.e., the 25^{th} and 75^{th} percentile values). Nineteen of the 45 respondents had systems outside of this typical range, with eight of them lower and 11 of them higher.

Of the eight respondents with capacity factors lower than the typical range, four of them reported they did not know why their capacity factor was atypical. In addition, when asked if they expected their production to be higher in future years, none of these four reported expecting higher production. The fifth respondent with a low capacity factor reported that he was aware of it and thought it was due to a system design problem. In particular, he reported that the way the system was designed prevented cleaning of the panels, and he did not expect production to be higher in the future. The sixth respondent in this group reported that he was not surprised with this result because the system is located in a coastal area. He also did not expect production to be any higher in the future. The seventh respondent reported that it had been determined that the system was producing less than expected and the installer agreed to add an additional 10 kW worth of panels to the system at no charge. Because of this change, this respondent expected his production to be higher now. The final respondent with a low capacity factor reported it was probably due to one of the system's 15 inverters not delivering data.

Of the 11 respondents with capacity factors higher than the typical range, six of them reported they had no idea why their system performance was above average. The remaining five respondents with atypically high performance provided the following comments on their systems:

- One reported that he was not surprised with the result because his system was installed on a large, flat roof area.
- Two respondents thought their high performance might be due to the orientation of the system and keeping the panels cleaned.

- One respondent with a particularly high capacity factor (33%) reported multiple contributing factors. He explained that the system faces south, it has an optimal angle and exposure, the panels are washed twice a year, and there were no high trees or pollen in the area. In addition, he reported the panels are arranged in a specific way to enhance system performance.
- Another respondent reported that his panels were also organized a particular way which is meant to make the system more efficient and productive in the earlier and latter parts of the day.
- One respondent reported that his system, which included cadmium telluride ("thin film") material, absorbed the light better than other types of PV technology, resulting in enhanced production.

Opinions on Maintenance Issues

When asked if they clean their PV panels, 30 of the 45 respondents reported they did. Their responses varied widely when describing how often they cleaned their panels. The most common response (from eight respondents) was twice a year. Following this, the three most common responses were once a year, quarterly, and as needed (four respondents each). The remaining responses ranged from every other day to occasionally in the summertime. One respondent reported he used to clean the panels in the summertime, but decided not to do it anymore because the cost outweighed the benefit. He further explained that while his output increased by 6% to 7%, the gain lasted only a month. Interestingly, about half of the respondents who reported cleaning their panels did not know if it made a difference in the electricity output, and most reported they did not monitor the output to know if it made a difference. Of the remaining respondents who did report an increase in output, estimates of increased output ranged from 3% to 20%. However, most of these respondents reported they believed cleaning panels helped increase output but could not quantify the difference.

The most common method reported for cleaning the modules was rinsing them with a hose and water (reported by nine respondents). Two respondents reported using a pressure cleaner, and two respondents reported having installed a sprinkler system over the panels. The remaining 17 respondents described using some form of brush, sponge or squeegee, and some of these reported using a mild detergent along with water. One respondent reported just using a squeegee on the panels after it rained.

The 30 respondents who reported cleaning their panels were also asked about the cost of that effort. Six reported contracting for the service, and three of these provided an estimate of their annual cost ($1,200, $5,000, and $8,000 to $10,000). Nineteen respondents reported using their own resources to do the cleaning. Most of these reported using one or two employees for a period of time ranging from one hour to two weeks for each cleaning project, depending on the size of the system. The most common response (from four respondents) was one person working two hours. Three respondents provided estimates of hourly rates ($14, $20 and $30 to $40).

Of the fifteen respondents who reported they did not clean their panels, six of them reported that they rely on rain to do that. Two respondents explained that the cost to hire someone to clean panels was prohibitive. A third respondent reported they did not clean their panels because the roof was four stories high with no water faucets.

Respondents were further asked if they had incurred any unforeseen expenses for their systems that had not been covered under warranty. Three of the 45 respondents reported they had. Two of these reported paying for roof repairs and the third reported paying for a broken panel. Only one of the respondents with roof damage reported a specific cost, stating that his "last roof repair was $3,000." Two other respondents reported they had to have inverters replaced and, while the cost of replacing the inverter was covered under warranty, days of generation were lost while the repairs were made.

Owner's Primary Objective for Installing System

Respondents were asked what had primarily influenced their decision regarding system size and type. In particular, they were asked if their decision had been primarily influenced by the desire for an expected rate of return or payback on their investment, the desire to offset a certain percentage of their utility bill or electrical energy usage, or some other reason. The answers varied, but the most common reason reported for installing a PV system was to offset their utility bill (reported as the primary reason by 21 of the 45 respondents and as a contributing reason by an additional 12 respondents). Of these respondents who identified energy savings as a motivating factor in installing their systems, 73% reported their expectations had been met (with four of these reporting it had exceeded their expectations). Six respondents reported their expectations had not been met (with one explaining their bill savings were 10% less than expected). Six respondents reported their primary motivation for installing their system was an environmental concern, and another five respondents reported their environmental commitment was a contributing factor, although not the primary reason for installing their PV system. Nine respondents reported that a return on their investment was a contributing factor for installing their system.

The remaining responses to this question involved a combination of reasons, including the reasons specified in the question, as well as environmental concerns, and use of the system as a training and marketing tool. In addition, one respondent reported he had received donations from private individuals to install a PV system, one respondent reported that PV was installed as part of a Leadership in Energy & Environmental Design (LEED)-certified building process, and one respondent reported soliciting bids for the most capacity within a specified budget and allowed the contractors to choose the optimal system.

System Satisfaction

Respondents were asked how satisfied they were with several aspects of their system's operations. First, they were asked to rate their satisfaction with system operations to date. Next, they were asked to rate their satisfaction with the system installer's follow-up service. Third, if the respondent had follow-up service from a hardware vendor, they were asked to rate their satisfaction with that service (only one respondent was in this category). Finally, respondents were asked how likely they would be to install another system like the one they have now. Ratings were reported on a scale of one to five, with one meaning "very unsatisfied" (or, in the case of the last question, "very unlikely"), and five meaning "very satisfied" (or "very likely"). Table 9-3 presents the PV system satisfaction results. As shown, all the questions resulted in an average response that indicated high satisfaction on the part of system owners.

Table 9-3: Satisfaction Ratings from PV Respondents

Question How satisfied are you with…	Average Response (n = number of respondents)
…your system's operations to date?	4.5 (n = 42)
…the system installer's follow-up service?	4.7 (n = 38)
…the system hardware vendor's follow-up service?	5.0 (n = 1)
…how likely would you be to install another system like it?	4.2 (n = 33)

System Owner Views on Cogeneration System Performance

As noted above, interviews were completed to collect performance information with 47 SGIP cogeneration system owners. Results from these interviews are summarized below. The cogeneration system interviews were remarkable in that almost every system had some unique characteristic based on the cogeneration application, the technology deployed, or the functioning of the equipment. Because of the wide variation among sampled systems, it is difficult to generalize from the sample to the entire SGIP cogeneration system population, or even to generalize about the sampled systems.

Opinions on System Availability

Seventy-eight percent of the cogeneration respondents experienced idle periods greater than three days. The mean idle period was 40 days for ICN systems and 54 days for MTN (MTR system sample was suppressed). As explained above, the total days in the idle periods were calculated by the program evaluator, based on metered data received for 2004, and are shown in Table 9-4 below.

During the interviews, respondents were asked to comment on these results. All reported being aware of the idle periods, and with few exceptions confirmed that the ENGO metering approximated their estimate of the number of idle days[3]. The reported causes of systems being idle were varied, but the most common (reported for 12 systems or 26%) related, at least in part, to problems associated with generation equipment. Heat recovery components were involved in idling 14% of the units sampled. Control problems were involved in 8% of idle systems. Design flaws were identified as the cause of 6% of the idle systems. (Note that these percentages do not total to 100% because several units reported more than one cause of idleness). Four respondents (8%) reported planned idleness due to the high cost of natural gas relative to electric rate (the "spark gap" issue[4]).

There was considerable optimism about improved future system availability across all respondents. Eighty-three percent of the respondents expected their systems to exhibit improved availability or that the causes of the idle period(s) were not likely to occur again.

Opinions on System Performance

Capacity factors based on 2004 metered data were calculated by the program evaluator for all cogeneration systems in the sample and are presented in Table 9-4.

[3] The program evaluator's idle period data was verified during the interviews and, where appropriate, modified to reflect system operators first-hand knowledge.

[4] "Spark gap" refers to the spread between the cost of electricity purchased from the utility grid versus the cost of purchasing gas to operate the self-generation system. Each system has a break-even point at which the short-run operation and maintenance cost is balance against the cost of purchasing electricity and heat from the utility. Lower electricity costs and/or especially high natural gas costs militate against operation of the self-generation system.

Table 9-4: Performance Characteristics for Sample Cogeneration Sites

Characteristic	Mean ICN*	Mean MTN*	Mean MTR*
Program total funded capacity 2003-2004 (kW)	30,103	7,255	1,150
Capacity in sample	14,873	1,550	870
Mean System Capacity for funded systems	301	154	230
Mean System Capacity Sampled	531	134	290
Mean Actual generation capacity factor (%)	54%	47%	37%
Mean Planned generation capacity factor (%)	68%	70%	N/A
Mean Actual heat recovery rate (kBtu/kWh)	1.9	4.0	N/A
Mean Planned heat recovery rate (kBtu/kWh)	3.8	5.9	N/A
Mean Number of days off-line during 2004	40	54	N/A

* **ICN** = Internal Combustion Engine Non-renewable; **MTN** = Microturbine Non-renewable; **MTR** = Microturbine Renewable

The sampled systems represent 49% of the total capacity of ICN, MTN and MTR systems funded through the SGIP Program (as of early 2005). The MTR systems seem to be over-sampled (76% of SGIP capacity) while the MTN systems were somewhat under-sampled at only 21% of total SGIP capacity. A comparison of average system size to sampled system size indicates that the sample is fairly representative of the entire SGIP cogeneration population with one exception: the sampled ICN systems are on average larger than the program average.

The results varied widely among systems. As shown in Table 9-4, the actual capacity factors calculated for 2004 were, on average, markedly lower than the planned capacity factors anticipated in the SGIP application. A similar result is seen for planned versus actual heat recovery rate. The reported causes of system idleness described above were generally also reported as responsible for the unexpectedly low electrical generation capacity factors. Maintenance problems and mechanical failures were often reported as the cause of lower capacity factors. Indeed, low capacity factors and large numbers of idle days are closely correlated. Similarly, the operators of low capacity factor systems expressed the expectation that their capacity factors will improve in the future due to improved maintenance procedures and resolved problems associated with system startup. Sixty-two percent of the systems were expected to have higher capacity factors in the future, and 33% were expected to remain the same. Only one system was expected to have a lower capacity factor in the future.

Not all systems deviated from their expected capacity factors negatively. Three respondents reported capacity factors exceeding their planned capacity factors. One of these system also exceeded expectations for their planned heat recovery rate.

Insofar as could be determined from the limited sample, there did not appear to be marked differences among the cogeneration technologies with respect to the planned capacity factor or the deviation between the planned and the actual 2004 capacity factor. Microturbines (MTN) seemed to perform better than ICN with respect to waste heat recovery (WHR) rates in both relative and absolute terms. The WHR rate for microturbines was 75% of the planned rate versus 50% of the planned rate for ICN systems.

Opinions on Operation and Maintenance Issues

Respondents were asked about the magnitude of their fuel, operations and maintenance costs as well as their relevant experience with routine and unplanned maintenance and/or repairs in 2004. Their responses and recent experience are summarized by technology in Table 9-5.

Table 9-5: Reported Operations & Maintenance/Repair Costs by Technology

O & M Item	All Technologies	ICN	MTN	MTR
Average annual maintenance cost (cents per kWh)	2.2 (n = 35)	2.0 (n = 18)	2.6 (n = 14)	3.1 (n = 3)
Average out-of-pocket cost for unplanned maintenance/repairs ($/ yr)	9,583 (n = 42)	$14,682 (n = 22)	$5,063 (n = 15)	$1,333 (n = 3)
Average Unplanned Maintenance Cost For Systems with costs>0	$10,344 (n = 9)	$64,600 (n = 5)	$24,500 (n = 3)	$4,000 (n = 1)
No. purchasing fuel from utilities	13	7	6	N/A
No. purchasing fuel from third parties	30	20	10	N/A
Average third party fuel cost ($/MMBtu)	6.60 (n = 11)	N/A	N/A	N/A

Note: n = number of respondents.

All but two respondents who reported routine maintenance costs had these costs covered by fixed annual contracts. In most cases, these contracts covered all unplanned maintenance costs (including non-SGIP-covered costs such as absorption chillers). Of the 27 respondents who would speculate about future maintenance costs, eleven thought that these costs would be lower, mainly due to increased capacity utilization on fixed price contracts. Of the six respondents who thought costs would increase, most thought this would be due to cost increase when contracts were renewed. Eleven respondents expected the costs to remain the same.

Almost all respondents who provided maintenance costs indicated that the costs were at or above the "rule of thumb" estimates of 1.5 cents/kWh for ICN and 2.0 cents/kWh for MTN.[5] The average ICN maintenance cost was 2.0 cents/kWh, while the MTN cost averaged 2.6 cents per kWh. As might be anticipated, microturbines utilizing landfill or digester gas had higher maintenance costs, averaging 3.1 cents per kWh. MTR systems had additional expenses both in purifying the fuel and in dealing with the effects of residual impurities on the generation prime mover.

Only nine systems had unplanned maintenance costs that they had to cover out-of-pocket. By dividing the unplanned maintenance cost by the average system size in each technology, one can derive the cost per installed kilowatt. This works out to $28/kW for ICN, $37/kW for MTN and $5/kW for MTR. Applying the average capacity factor for each technology yields an average cost per kWh for unplanned maintenance of 0.5 cents for ICN , 0.9 cents for MTR and 0.1 cent for MTR systems. These costs are in addition to the cost of routine maintenance reported in the previous paragraphs.

Most respondents were unwilling or unable to provide their average fuel costs for 2004. Of the 11 observations we were able to sample, the average price reported was $6.60 cents per MMBtu. Many respondents reported that the cost of natural gas in 2004 was higher than anticipated. Furthermore, five respondents reported that these higher fuel costs were a factor in lowering the operational capacity factor for their cogeneration systems (the "spark gap" issue referred to above). Three others were holding off on repairs pending improvement in the spark gap situation.

Primary Objective for Installing System

Respondents were asked what had primarily influenced their decision regarding their system size and type and whether their expectations had been met. In particular, they were asked if their decision had been primarily influenced by the desire for an expected rate of return or payback on their investment, the desire to offset a certain percentage of their utility bill, the desire to offset a certain percentage of their electrical energy usage, or some other reason.

Thirty-five of the 47 cogeneration respondents (74%) considered payback an important factor in selecting system size and type. Other considerations reported included: 1) backup generation to avoid even brief utility supply disruptions (reported by four food processors and one electronics equipment manufacturer), 2) reduction in summer peak demand, 3) limitation on ability to accommodate exhaust gas from microturbines (reported by one hazardous waste landfill operator), and 4) limitation on SGIP system size.

[5] These "rule of thumb" estimates were provided to the respondent as part of the interview question.

System Satisfaction

As described above for PV respondents, cogeneration respondents were asked how satisfied they were with several aspects of system operations. Table 9-6 presents these results on system owner satisfaction.

Table 9-6: Satisfaction Ratings from Cogeneration Respondents

Question How satisfied are you with…	Average Response (n = number of respondents)			
	ICN	MTN	MTR	All Systems
Did the system meet your required performance criteria?	Yes 52% (n = 11) No 48% (n = 10)	Yes 25% (n = 1) No 75% (n=9)	Yes 67% (n = 2) No 33% (n=1)	Yes 44% -(n = 16) No 56% (n = 20)
…your system's operations to date?	3.0 (n = 23)	3.0 (n = 12)	3.0 (n = 3)	3.0 (n = 38)
…the system installer's follow-up service?	3.8 (n = 22)	2.6 (n = 12)	4.2 (n = 3)	3.4 (n = 37)
…the system hardware vendor's follow-up service?	3.2 (n = 20)	2.9 (n = 11)	3.3 (n = 3)	3.2 (n = 34)
How likely would you be to install another system like it?	4.0 (n = 23)	2.8 (n = 12)	4.3 (n = 3)	3.7 (n = 38)

Ratings were reported on a scale of one (1) to five (5), with 1 meaning "very unsatisfied" (or, in the case of the last question, "very unlikely"), and 5 meaning "very satisfied" (or "very likely").

As indicated in Table 9-6, despite the marked negative departures from planned capacity factors and heat recovery rates, and the unexpectedly high natural gas prices in 2004, about half of the respondents felt that their system met their performance criteria. Respondents were generally satisfied with the performance of their systems, reporting an overall satisfaction rate of 3.0. Remarkably, all three cogeneration technologies had almost identical average satisfaction rates (although there are small differences in the third significant figure). This is difficult to understand given the disparity among the technologies with regard the proportion that met their performance criteria (52% for ICN, 25% for MTN and 67% for MTR).

The ICN respondents were fairly optimistic that their systems would eventually perform better as evidenced by the comparison of their overall system rating to date (averaging 3.0) and their willingness to install a similar system (averaging 4.0). This apparent paradox might be better understood based on the system owners' general beliefs that the poor performance of the systems in 2004 were the result of either: 1) start-up difficulties that have been worked out (or are in the process of being worked out), or 2) the result of higher than expected fuel prices (that forced them to restrict operations at the times of high fuel price) coupled with lower electric retail prices.

Microturbine technology respondents were more consistent in their evaluation of the performance to date and their willingness to install a similar system. The relatively poor performance of MTN systems is reflected in the owners' relatively low average willingness to install a similar system. The combination of system unreliability and high gas prices has led to the fairly low willingness to install similar systems in other situations. Conversely, the relatively good performance of the MTR systems combined with their immunity from gas price increases led to relatively high willingness to install more of these systems in similar situations, although it might be misleading to generalize too much from this small sample.

MTN system respondents gave lower average satisfaction ratings for the system installer and the hardware vendor's follow-up service (2.6 and 2.9, respectively). This compares with average ratings from 3.2 to 4.0 for these categories for ICN and MTR systems.

9.5 Summary of Key Findings

PV Systems

The following are some key findings summarized from the results of interviews with PV system owners based on system operation during 2004:

- Respondents whose systems exhibited idle days in 2004 were not concerned. Most did not know why their system had been idle, although several offered possible reasons.
- Most system owners were not aware of their capacity factor and were not surprised or concerned to learn of its value. Most respondents who offered explanations for why their performance was atypical attributed it to system design.
- Most (67%) of PV system owners interviewed reported that they clean their solar panels. The most commonly reported frequency for cleaning was twice a year. Most system owners used their own staff or maintenance crew to clean the panels, while six reported hiring an independent contractor to do the job. The two most common reasons given for not cleaning the panels were that it was cost prohibitive and "the rain takes care of it."
- Most system owners had not experienced any out-of-warranty maintenance costs on their systems. However, two reported paying for roof repairs and one reported paying for a broken panel.
- The most common reason for installing a PV system (reported by 33 respondents) was to offset the utility bill. Most (73%) of these reported their expectations regarding their bill savings had been met or exceeded, while 18% reported their

expectations had not been met. The remaining respondents were unsure of savings or had not set savings expectations.

- The results of these interviews reveal that system owners are, on average, very satisfied with their SGIP PV systems. Most, given the need, would install another system, and many reported they were in the process of doing so.

Cogeneration Systems

The following are some key preliminary findings summarized from the results of interviews with SGIP cogeneration system owners based on system operation during 2004:

- The respondents with high numbers of idle days and/or low annual operating capacity factors in 2004 were aware of their system’s poor performance. Generally, these participants have already taken action to remedy the causative problems.
- Respondents were optimistic that actions taken, especially actions to improve maintenance, would increase future capacity utilization and decrease unplanned outages.
- There was considerable concern about the high cost and volatility of natural gas markets. This had a negative effect on the performance of some systems whose operators ran the units less or deferred maintenance and repairs until the economics turned more favorable. In addition, the high and volatile fuel prices reduced the respondent’s overall satisfaction with the system and decreased their willingness to install similar equipment in other situations.
- Heat recovery equipment malfunction was frequently mentioned as a factor in both decreased waste heat utilization and overall poor performance of the cogeneration system.
- Although not reported in the compiled data, the evaluator noticed a trend favoring continuous operation applications versus those involving diurnal (daily) cycling. Operators with continuously operating systems had fewer unplanned maintenance problems and better system performance than those that attempted diurnal cycling.
- Microturbines running on natural gas had a higher incidence of unplanned maintenance than other technologies. MTN systems also had higher numbers of idle days and lower capacity factors than the other technologies.

Limitations on the Use of Results

It is important to note that any conclusions drawn from the results of these interviews should be interpreted very carefully due to the small sample sizes. In particular, when looking at results for any segment of the sample, the number of responses may not be sufficient to infer a similar result for a larger group. The sample for these interviews was selected primarily to represent opinions of system owners for the sites analyzed in this impact evaluation. It was not selected to accurately represent the population of SGIP hosts and applicants, nor was it selected to represent the population of DG system owners in general.

In addition, as mentioned above, the results for cogeneration projects are particular to the sites interviewed due to the unique situations faced by individual system owners. These results should be interpreted with their individual context in mind and not readily generalized to larger populations.

10

Summary of Results and Key Findings

10.1 Introduction

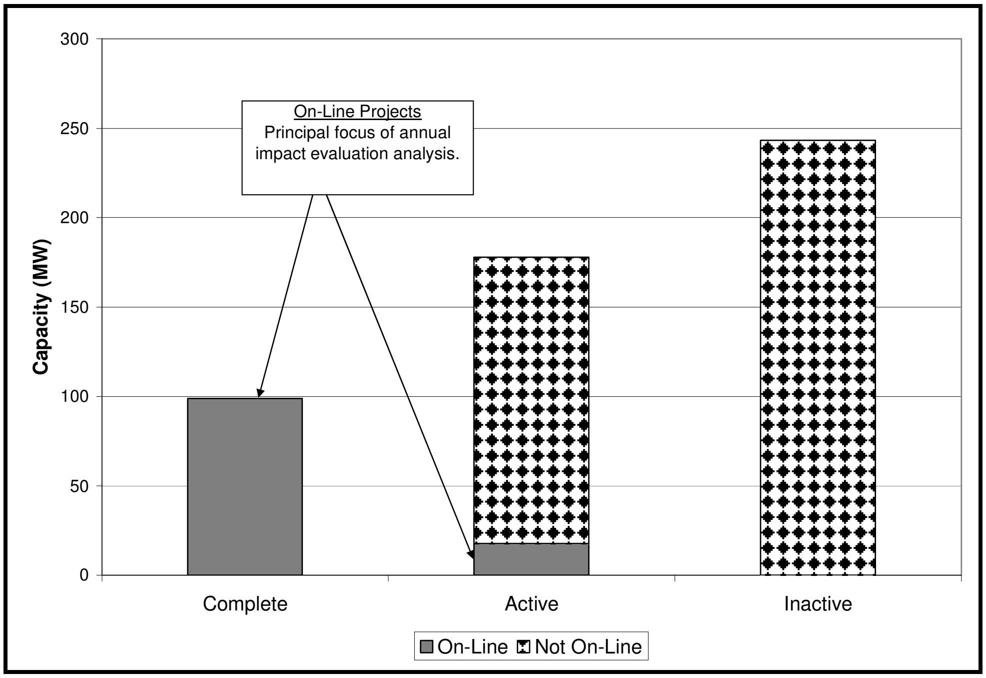
This section provides evaluation summary results and key findings. A variety of means were used to assess the impact of the SGIP during 2004. Metered data, surveys of SGIP participants, and documentation produced during program implementation contributed to the study. Summary results and key findings presented below will contribute significantly to the overall evaluation for the SGIP. That overall plan includes process evaluation, impact evaluation, and cost-effectiveness evaluation. This fourth-year impact evaluation report may also be used to assess progress on meeting criteria C1.B, C1.C and C3.B as described previously in Table 3-1.

10.2 Summary of Results

Program Status

A total of 116 MW of SGIP Complete and Active projects were determined to be on-line as of December 31, 2004. The performance of these on-line projects is the main focus of this annual assessment of SGIP impact on distributed generation in California. However, as shown in Figure 10-1, many projects entering the SGIP during 2001-2004 remain Active in the program but are not yet on-line. These Active projects are in various stages of development, including design, financing, procurement, construction and commissioning. These Active projects are in various stages of development, including design, financing, procurement, construction and commissioning. Some of the Active projects are on a wait list. Current program records indicate that the on-line capacity corresponding to all PY01-PY04 SGIP projects may eventually total as much as 277 MW, subject to program funding constraints.

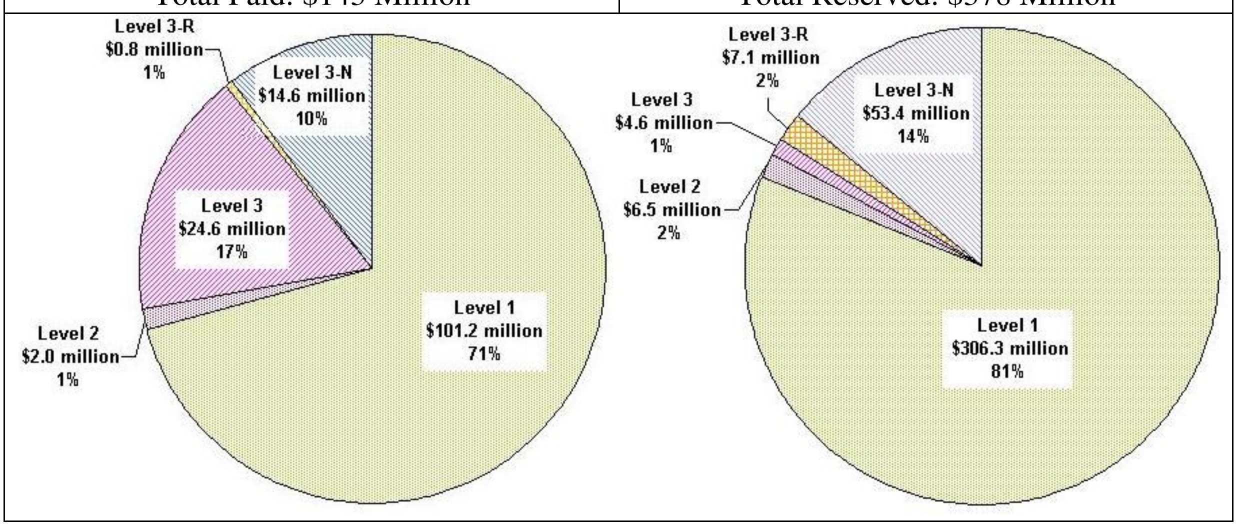
Figure 10-1: Summary of PY01-PY04 SGIP Project Status as of 12/31/2004



As shown in Figure 10-2, a total of $143 million of incentives had been paid by Administrators for completed projects as of the end of 2004. Level 1 PV projects account for the majority of incentives paid and reserved.[1]

Figure 10-2: Incentives Paid or Reserved for Complete & Active Projects

Completed Projects Total Paid: $143 Million	Active Projects Total Reserved: $378 Million



[1] All Complete Level 1 projects are PV. There are several Active Level 1 wind and renewable fuel cell projects, however, PV accounts for 97% of incentives reserved for Active Level 1 projects.

The SGIP's financial support of distributed generation projects in California is summarized in Figure 10-2. Total eligible project costs (private investment plus the paid/reserved SGIP incentive) corresponding to Complete and Active SGIP projects exceed $900 million.

Electric Demand Impact

Electrical demand and energy impacts for projects coming on-line prior to December 31, 2004, were calculated using available metered data and other system characteristics information from the program tracking systems maintained by the Program Administrators. As described in Section 6 of this report, electric net generator output (ENGO) metered data are not yet being collected from all SGIP projects on-line as of the end of 2004.

Overall program demand impact coincident with 2004 CAISO system peak load are summarized below in Table 10-1. In 2004 the CAISO system peak reached a maximum value of 45,562 MW on September 8 during the hour from 15:00 to 16:00 PDT (3 to 4 PM). Total rebated capacity of the 388 on-line SGIP projects exceeded 103 MW. Total impact of the SGIP coincident with the CAISO peak load is estimated at just under 55 MW.

Level 3/3-N/3-R engines and turbines account for approximately 44 MW, or 81% of this total 2004 peak demand impact. The total program-level system peak demand impact for incentive Level 1 PV systems is estimated to have been approximately 9.9 MW, or 18% of the total 2004 peak demand impact.

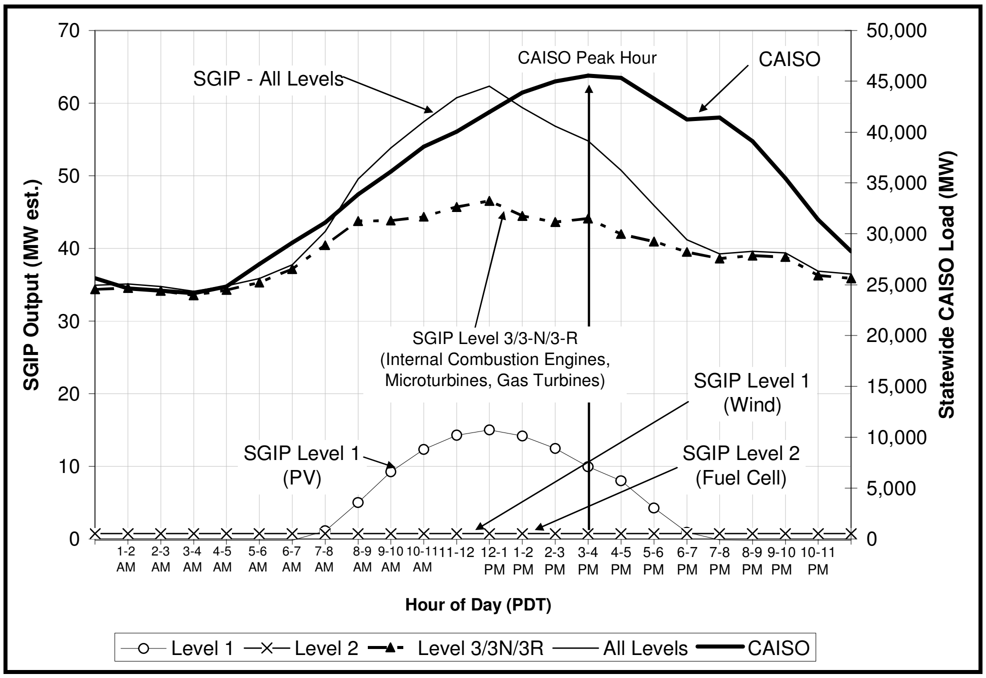
The estimated demand impact for Level 3/3-N/3-R systems corresponds to 0.58 kW per 1.00 kW of installed system size based on rebated capacity. The estimated peak demand impact for PV corresponds to 0.39 kW per 1.00 kW of PV system size based on rebated capacity.

Table 10-1: Program Electric Impact Coincident with 2004 CAISO Peak Load

Level / Basis	On-Line Systems (n)	On-Line Capacity (kW)	Peak Demand Impact (kW_P)	Unit Demand Impact (kW_P/kW)
Level 1 PV	235	25,365	9,938	0.39
Level 1 Wind	1	950	0	0.00
Level 2 Fuel Cell	2	800	744	0.93
Level 3/3-N/3-R Engine/Turbine	150	75,930	44,115	0.58
Total	**388**	**103,045**	**54,797**	**0.53**

The peak-day profiles of CAISO system load, as well as SGIP project generation, are illustrated in Figure 10-3. While PV system power output was substantial on the day of the CAISO system peak, the PV output curve's shape is more pointed than the CAISO load's shape. After 1 PM the total output of the 235 on-line PV systems began falling, whereas CAISO loads continued to increase for several hours. The shape of the output curve estimated for the 150 on-line engines and turbines aligns well with the CAISO system peak from 3 p.m. to 4 p.m., and the two curves maintain a similar relationship during both diurnal shoulder periods (before and after the peak hour).

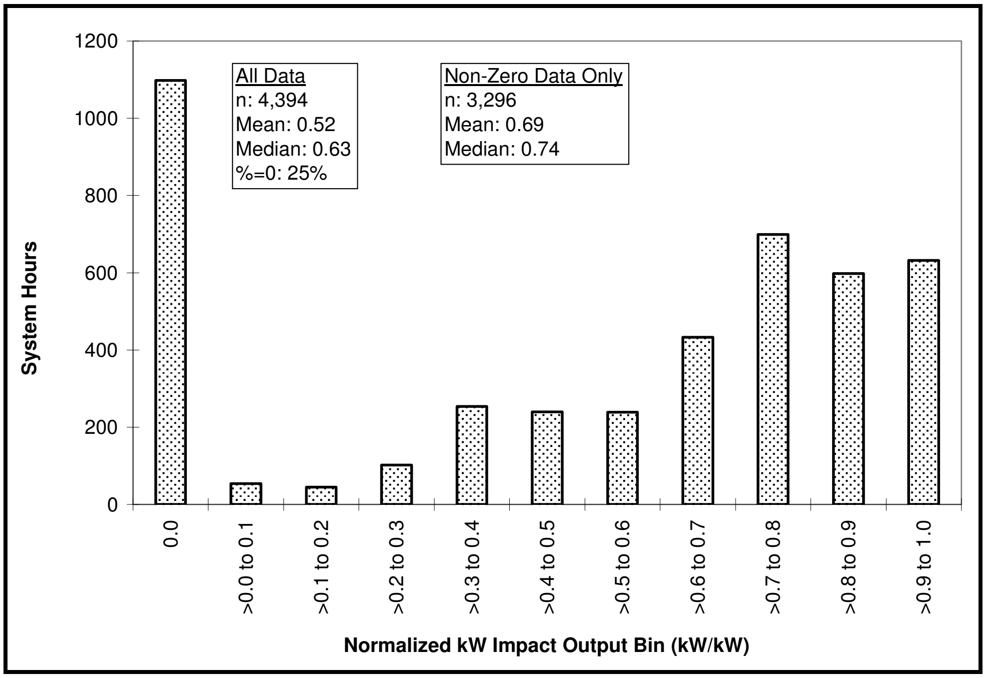
Figure 10-3: CAISO 2004 Peak Day Loads & Estimated Total SGIP Generation



To more completely characterize SGIP demand impacts, normalized hourly output of the metered Level 3/3-N/3-R systems during 2004 coincident with the CAISO maximum loads (i.e., based on the five peak hours of each month) are summarized in Figure 10-4. Each "System Hour" represents a 60-minute period during which a system was "on-line". In some instances systems were on-line but not operational. Such idle systems influence the weighted average demand impact of the SGIP systems.

Whereas for PV both intra- and inter-day variability were significant, for Level 3/3-N/3-R systems it is more meaningful to consider all 60 CAISO-maximum load hours as a single group. These 60 hours correspond to a total of 4,394 system hours (i.e., the average number of "on-line," but not necessarily operational, systems was 73).

Figure 10-4: Demand Impact Per Unit of Rebated Capacity – Level 3/3-N



For the group of 4,394 CAISO-maximum system hours, normalized power output of the monitored Level 3/3-N/3-R systems averaged 0.52 kW of power output per 1.00 kW of rebated system size during the top five peak load hours each month in 2004. The idle units (0.0 kW/kW Normalized Output) play an important role in reducing the average output of all rebated units during hours when CAISO loads reach their maximum values.

There are many possible explanations for the results presented in Figure 10-4. Possibilities include: 1) relationships between cogeneration system size and facility electric load magnitude or timing could constrain electric output in some cases; 2) mechanical failure; 3) change in ownership or turnover among operations staff; and 4) uncertainty regarding cogeneration system cost-effectiveness in the face of current gas prices and retail electric rates.

Electric Energy Impact

Overall program electrical energy impacts are summarized by Quarter in 2004 in Table 10-2. While Level 3 projects (i.e., 3/3-N/3-R engines and turbines) account for 80% of demand impacts, they account for 88% of total energy impact. This difference is due to the fact that the average capacity factor of these Level 3 engines and turbines is greater than that for the Level 1 PV systems. A portion of the variability in energy production observed across quarters is attributable to systems coming on-line throughout 2004. This complicates interpretation and use of absolute measures of program electric energy impacts (i.e., MWh).

Table 10-2: Program Energy Impact in 2004 by Quarter (MWh)

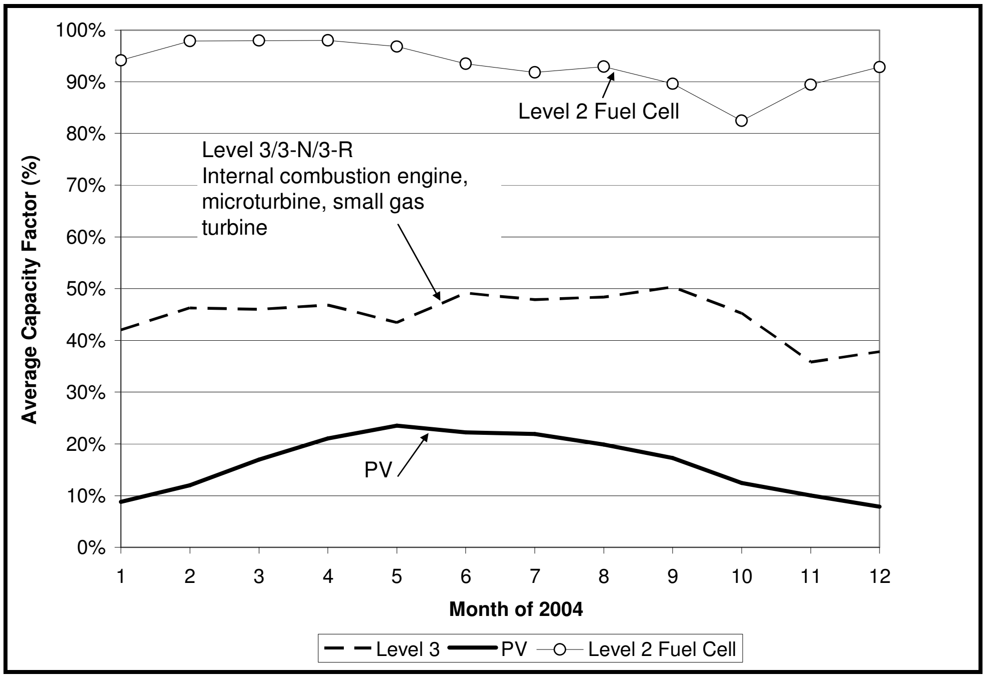
Level / Basis	Q1-2004	Q2-2004	Q3-2004	Q4-2004	Total MWh
Level 1 PV	5,612	11,020	10,649	6,553	33,835
Level 1 Wind	0	0	0	339	339
Level 2 Fuel Cell	422	689	1,616	1,559	4,286
Level 3/3-N/3-R ICE/Turbine	63,276	72,488	79,856	70,574	286,193
Total	**69,311**	**84,197**	**92,120**	**79,025**	**324,653**

In Figure 10-5 the energy production characteristics of the operational systems are expressed on a normalized basis to enable comparison of the several different distributed generation technologies.

As expected, normalized PV energy production levels reach their maximum values in the summer season and decrease towards the winter season as the intensity and duration of incident solar radiation falls off, and increased incidence of storms and other weather conditions affect the availability of solar radiation. PV system power output, then, is primarily governed by weather.

The capacity factor of engines and turbines is influenced by fundamentally different factors. Engine and turbine power output is primarily governed by thermal demand and on/off switches, and is generally required to be controlled to a level such that substantial quantities of power are not exported to the grid. (Whereas PV systems in the program are eligible for net-metering tariffs that enable them to produce more power than is consumed by the facility during certain hours.) Depending on the relative size of the engine or microturbine system, when facility power requirements are low - the power output of the distributed generation system might need to be throttled down to prevent export of power to the grid. Consequently, the monthly average capacity factor may be strongly influenced by facility operating hours (i.e., 1-, 2-, or 3-shift).

Figure 10-5: Average Capacity Factor by Month (CY04)



Cogeneration System Energy Impact

Level 2 fuel cells and Level 3/3-N engines/turbines are subject to certain heat recovery and system efficiency requirements during the implementation stage of the SGIP. A variety of means are used to recover heat for useful purposes, and to apply that heat to provide various forms of heating and cooling services. The end-uses served by recovered useful thermal energy are summarized in Table 10-3, which includes Complete and Active projects on-line by December 31, 2004.

Table 10-3: Cogeneration System Thermal End-Uses and Data Availability

	On-Line as of 12/31/2004		2004 Data Availability	
End-Use	**On-Line Systems (n)**	**On-Line Capacity (kW)**	**On-Line Systems (n)**	**On-Line Capacity (kW)**
Heating Only	96	39,938	19	7,874
Heating & Cooling	38	21,726	7	4,520
Cooling Only	18	15,261	6	4,063
Total	**156**	**76,925**	**32**	**16,457**

To assess actual heat recovery and system efficiency performance, useful heat recovery is monitored. In some cases, availability of CY04 data was not sufficient to estimate PUC 218.5 thermal energy proportions or efficiencies due to their annual basis requirement.

These sites with insufficient data were not included in the summary of 2004 data availability presented in Table 10-3 or in the subsequent summaries of system efficiency results.

Level 2 fuel cell and Level 3/3N engine/turbine cogeneration system designs are required to demonstrate (on paper through engineering design documentation) achievement of a PUC 218.5(b) minimum efficiency calculated as the sum of ENGO and one-half the useful thermal energy, divided by any natural gas (and oil)[2] energy input. Available metered thermal data collected from these on-line cogeneration projects were used to calculate overall system efficiency incorporating both electricity produced as well as useful heat recovered. Results of the analysis for Level 3/3-N projects are summarized in Table 10-4. At least ten months of operating data were available for 21 of the 31 systems. In 10 other cases at least six months of data were available for either the first half or the second half of 2004. While the basis of the PUC 218.5 proportions and efficiencies is annual, when at least 6 months of data from several seasons are available, the calculated results were annualized and thus were considered representative of what could be expected on an annual basis.

Metered data collected to date suggest that nine of the 31 monitored Level 3/3-N projects achieved the 218.5 (b) overall system efficiency target of 42.5%. Four of these nine systems utilize recovered heat for both heating and cooling. Cogeneration systems utilizing recovered heat in this manner account for 23% of the 31 systems examined, but 44% of the nine systems achieving the prescribed PUC 218.5 (b) efficiency. Four of the remaining five systems meeting the 218.5 (b) requirement utilized recovered heat for heating only, while one utilized recovered heat for cooling only.

The limited quantities of cogeneration system data available for this impact analysis suggest the possibility of systematic negative variance between planned system efficiencies and actual system efficiencies. However, collection and analysis of additional data is required before definitive conclusions can be drawn. Data were available for one Level 2 fuel cell project, which satisfied the requirements of PUC 218.5 (a) and achieved a 218.5 (b) system efficiency exceeding 50%.

Table 10-4: Level 3/3-N Cogeneration System Efficiencies (n=31)

Summary Statistic	218.5 (b) Efficiency	Overall Plant Efficiency
Min	19%	22%
Max	54%	82%
Median	36%	46%
Mean	37%	49%

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[2] Only natural gas (and renewable) fueled cogeneration systems are eligible for incentives under the SGIP.

Results of an analysis of electrical conversion efficiencies and average heat recovery rates are presented in Table 10-5. Gross electric generator output data and engine/turbine fuel usage data were combined in a calculation of engine/turbine electric conversion efficiency. In the case of reciprocating engines (ICE), actual electrical conversion efficiencies of approximately 30% are typical. This typical result is less than electrical conversion efficiencies normally found in published technical specifications by engine-genset manufacturers. These nominal nameplate electrical generating efficiencies published by manufacturers generally exceed 30%, and sometimes exceed 35%.

Table 10-5: Level 3/3-N Electrical Conversion Efficiency[3] and Average Normalized Heat Recovery Rates

Summary Statistic	Elec. Conversion Effic. ICE	MT*	Useful Thermal Energy Recovery
n	36	17	31
Min	20%	16%	0.2 kBtu/kWh
Max	38%	27%	8.5 kBtu/kWh
Median	30%	23%	2.9 kBtu/kWh
Mean	30%	22%	3.3 kBtu/kWh
Std Dev	4%	3%	2.1 kBtu/kWh
Coefficient of Variation	0.1	0.1	0.6

*Microturbines

Normalization of the recovered useful thermal energy data enables direct comparison of systems of different sizes. Normalized actual useful heat recovery rates are therefore expressed in terms of kBtu of useful recovered heat per kWh of net generator electric energy production. For the 31 Level 3/3-N systems for which 2004 data were available for this analysis, substantial variability among systems was observed in the normalized measure of heat recovery. This variability in part reflects the incidence of several projects with very minimal heat recovery, as well as the considerable variability (i.e., two to five kBtu/kWh) observed for the projects where appreciable quantities of useful heat were recovered.

Observed electrical efficiencies for microturbines were lower than those for reciprocating engines, as expected. The median efficiency actually observed was 23%. This is lower than nominal microturbine efficiencies typically published by manufacturers (approximately 28%). In the context of PUC 218.5 (b) efficiency calculations, these variances are relatively more significant than those on the useful recovered heat side of the equation, because only 50% credit is given to the recovered heat in the 218.5 (b) efficiency equation.

[3] The electrical conversion efficiencies are calculated as the ratio of gross electric generator output to lower heating value of fuel content after converting both to an identical units basis.

In general the actual useful heat recovery rates observed in 2004 were less than projected by engineering calculations completed during the design stage of cogeneration system project development. The variance is due to numerous factors, including design, operational, and reliability problems, and unanticipated operational conditions. Information about these problems is being collected as part of the limited-scope process evaluation described previously. Results of the current targeted process evaluation will be presented in a separate report, and will help explain the quantitative results presented in this report.

Finally, it must be emphasized that the quantity of useful recovered heat data available for this analysis is small. While the total capacity of operational cogeneration systems approached 83 MW at the end of 2004, this analysis included useful recovered heat data for projects totaling just over 17 MW. In addition, for some of these projects less than a complete year of data were available. This monitored group does not represent a statistical sample; rather, it could best be characterized as a monitored group for which useful recovered heat data were available. While results presented in this report for 2004 are suggestive of the possibility of systematic deviation between planned system efficiency and actual system efficiency, data availability constraints preclude drawing definitive conclusions at this time.

10.3 Key Findings

Several key findings of this fourth-year impact evaluation include:

Level 3/3-N Demand Impacts

During hours when CAISO system reaches maximum values, there was substantial variability in engine/microturbine output (including substantial portions that were not operating). The weighted average contribution to demand impacts during the hour of the CAISO system peak may be lower than expected (i.e., 0.58 kW per 1.00 kW of system capacity based on rebated size).

Level 1 PV Demand Impacts

During hours when CAISO system loads reach monthly maximum values PV delivers demand impact not only in summer months, but also in certain spring and fall months. The weighted average contribution to demand impact during the hour of the CAISO system peak (i.e., 0.39 kW per 1.00 kW of system capacity based on rebated size) may be lower than expected from PV systems. This result is largely explained by known factors influencing actual PV system power output, as compared to rated system sizes used for establishing the rebate.

Cogeneration System Actual Operating Efficiencies

The limited quantities of cogeneration system data available for this impact analysis suggest the possibility of systematic negative variance between planned and actual. Data available to date suggest that only nine of the 29 monitored Level 3/3-N cogeneration systems appears likely to actually achieve 42.5% PUC 218.5 (b) efficiency on an annual basis.

SGIP Participant Perspectives

The following are some key findings summarized from the preliminary results of interviews with 45 SGIP PV system owners based upon their system operations experienced during 2004 (more detail on these interviews is found in Section 9 and Appendices B and C of this report):

- The most common reason for installing a PV system was to offset the utility bill. . The second most common reason given was to help the environment.
- The results of these interviews reveal that PV system owners are, on average, very satisfied with their SGIP systems. Most, given the need, would install another system, and many reported they are in the process of doing so.
- Most (67%) PV system owners interviewed reported that they clean their solar panels. The frequency of cleaning ranged from twice a week to once a year. Most system owners used their own staff or maintenance crew to clean the panels, while two reported hiring an independent contractor to do the job. The two most common reasons given for not cleaning the panels were that it was cost prohibitive and the rain "takes care of it."
- Most system owners had not experienced any out-of-warranty maintenance costs on their systems. However, two reported paying for roof repairs and one reported paying for a broken panel.

The following are some key preliminary findings summarized from the results of interviews with 47 SGIP cogeneration system owners based upon their system operations experienced during 2004 (more detail on these interviews is found in Section 9 and Appendices B and C of this report):

- Although energy production to date has been below planned levels, respondents were optimistic that actions taken, especially actions to improve maintenance, would increase future capacity utilization and decrease unplanned outages.
- There was considerable concern about the high cost and volatility of natural gas markets.
- Heat utilization equipment malfunction was frequently mentioned as a factor in both decreased waste heat utilization and overall poor performance of the cogeneration system.

- The respondents with low annual operating capacity factors in 2004 were aware of their system's poor performance and generally these participants had taken action to remedy the causative problems.

10.4 Implications of Findings

In assigning implications to the above findings of this impacts assessment, although the system electric generation data were generally rich, it must be noted in many cases that the quantity of useful thermal energy data available for this analysis is small. For some of these projects much less than a complete year of data were available, and data analysis efforts were complicated by the fact that additional evaluated projects continued to come on-line throughout the year.

Taking the above caveat into consideration, overall, while the SGIP is very well-subscribed and program participants are on average satisfied with their SGIP systems, it appears that many of the Level 3/3-N cogeneration systems are not performing as well or operating as many hours as originally expected. The weighted average annual capacity factor of these cogeneration systems was 45% during 2004 and during hours when CAISO loads reached their peak a surprisingly large proportion of the engines and turbine generators were not operating.

Dissemination of this impact evaluation's findings could contribute to better performance for cogeneration systems installed in the future. If prospective SGIP participants are aware of challenges faced by current participants then they may be better able to make decisions concerning system design and specification that will yield improved performance. This is true for the system vendors as well as for system owners because as the distributed generation market grows there will be new market entrants on the vendor side as well as on the customer side. Currently plans are in place to develop brochures summarizing key information contained in this and other program evaluation reports. These materials will be made available on the Web sites of the SGIP's Program Administrators. Other means of outreach, including public workshops and presentations to key stakeholders, will also contribute to further dissemination of these SGIP evaluation findings.

Appendix A

PV System Performance Details

A.1 Introduction

It was noted earlier that PV system performance is different from the performance of other types of DG for several interesting reasons. In this Appendix this topic is examined in greater detail. Background information is presented along with new material concerning PV module soiling and washing. A principal purpose of this Appendix is to use data and results for a few representative cases to illustrate key concepts relating to PV system soiling. Additional data collection and analysis would be required to develop specific guidelines concerning the economics of PV module washing. Several recommendations along these lines are presented at the end of this Appendix.

A principle underlying PV economics is that relatively high initial capital costs are offset by very low operating costs. To optimize a PV system's economic performance its electric output performance must be maintained cost effectively. A well-designed PV system may have no operating cost other than that of an occasional module washing. Generally a low-tech and low-skill task, washing may be the highest-value and perhaps the only means a PV system owner has to optimize economic performance short of system modification. An optimal economic level of module washing depends primarily on performance impact of module soiling.

As described below, PV studies typically estimate soiling losses to be in a range from five to ten percent of annual energy output. Some reports from SGIP PV participants have suggested that under certain circumstances PV soiling losses may be much higher. This Appendix examines the performance impacts of soiling in response to such concerns of SGIP participants and program administrators and in recognition of the potential for improving the economic performance of SGIP systems by developing and sharing information regarding the possible benefits of PV module washing.

The performance impacts of soiling were examined by comparing daily energy output from systems on clear weather days relative to the number of days since a heavy rain event may have washed modules clean. The hypothesis was that heavy rains would wash away soiling so that power output on subsequent clear days would decline as soiling gradually re-accumulated.

Secondary data sources and proxy data were utilized for this examination. No site-specific plane-of-array insolation or module temperature data were collected under the scope of work for the program evaluation. Detailed performance monitoring would entail collection of select environmental data (i.e., plane of array solar insolation, ambient/module temperatures, wind speed/direction) coincident with photovoltaic or wind system electric power output, as well as information on washing activities and rain events. Due to the limitations of available data the examination was kept simple and succinct.

A.2 Background

Over time PV modules may become soiled by surface accumulation of ambient dust or other material such as pigeon droppings or waste vented from within a building. Photographs from numerous SGIP PV site inspection reports indicate such conditions. Soiling reduces module power output by preventing incident solar radiation from reaching the photovoltaic material surface. Where soiling is frequent or heavy, the decrease in power output resulting from this shading effect may be considerable and energy production lost. It then may be advisable to institute a regular module washing schedule. As described in Section 9 of this report, most PV system owners interviewed reported that they do wash their modules. Some PV systems even have sprinkler systems to wash and cool modules, while others have sprinklers only for module cooling.

Soiling is largely a dry-season phenomenon caused by gradual accumulation of airborne debris from nearby fields, roads, or parking lots. Thus soiling may be at a maximum in late summer, just before the rainy season begins to rinse away such debris. Soiling also can occur at any time and quite suddenly. It can result from single events and from a variety of debris. For example roof-mounted modules may be quickly shrouded by rooftop venting of industrial process wastes. Likewise agricultural plowing can generate dust clouds and rapid soiling.

Heavy rainfall with blowing winds can wash much soiling from PV modules. This may be the only washing some modules ever receive. On the other hand, light rainfall can exacerbate soiling by causing more dust to adhere to lightly wetted modules. As rain evaporates from droplets or puddles, the captured debris is deposit on the module surface. Puddles on framed edges of tilted modules often leave visible debris lines where puddle edges had been.

Soiling is one of the factors explaining the observed rate of demand impact yielded by SGIP PV systems. The potential for performance losses on hot summer afternoons is illustrated in Table A-1, along with the contribution ascribed to soiling. Table A-1 outlines an engineering estimate of peak power output based on published information regarding PV system performance. It shows how peak power, beginning with 1 kW (Basis: rebated size) of horizontal PV system capacity, potentially dwindles due to several factors.

Table A-1: Illustration of Factors Influencing PV System Peak Output

Description	Value	Basis	Summary
Rebated System Size	1.00	Total PTC DC x Inv. Eff.	1.00
Production Tolerance	0.95	PV Design Guide*	0.95
Power output on hot summer afternoon is less than under PTC weather conditions	0.95	CEC research**	0.90
Inverter efficiency at full load is less than rated maximum inverter efficiency	0.95	Assume 95% maximum rated efficiency and 90% full-load efficiency at actual ambient temp.	0.86
Soiling	0.93	PV Design Guide	0.80
Mismatch & wiring	0.95	PV Design Guide	0.76
During late-afternoon hours the sun is not directly overhead	1-2 PM: 1.01 2-3 PM: 0.96 3-4 PM: 0.86	Analysis of hourly TMY data for San Francisco (Summertime, Clear Days)	1-2 PM: 0.77 2-3 PM: 0.73 3-4 PM: 0.65

*A Guide to Photovoltaic (PV) System Design and Installation, Prepared for California Energy Commission Technology Systems Division, Prepared by Endecon Engineering, Publication #500-01-020, June 2001.

**Measured Output for Nineteen Residential PV Systems: Updated Analysis of Actual System Performance and Net Metering Impacts, Boleyn, D.R., Lilly, P., Scheuermann, K., and Miller, S., Proceedings of ASES Annual Conference, American Solar Energy Society, 2002.

For purposes of determining rebates, PV system sizes are calculated as the product of cumulative estimated module DC power output under PTC conditions and inverter maximum DC to AC conversion efficiency, as shown for Rebated System Size in Table A-1. The Value column of Table A-1 shows the subsequent factors that reduce performance. Note that apart from the influence of the sun's position from hours 3-4 PM, the soiling factor is the lowest value. Also note from the descriptions that soiling is the one value a PV system owner has any ability to change without system modification. Table A-1 indicates in the Summary column that a relatively conservative estimate of power output for a horizontal PV system would be 0.65 kW of power output per kW of rebated PV system size on clear days for the hour from 3 to 4 PM PDT.

The CEC's 2001 guide to PV systems describes soiling and module temperature among several key factors affecting PV output[1]:

[1] A Guide to Photovoltaic (PV) System Design and Installation, Prepared for California Energy Commission Technology Systems Division, Prepared by Endecon Engineering, Publication #500-01-020, June.

> *2.3.1. Factors Affecting Output*
> *Temperature*
> *Module output power reduces as module temperature increases. When operating on a roof, a solar module will heat up substantially, reaching inner temperatures of 50-75 oC. For crystalline modules, a typical temperature reduction factor recommended by the CEC is 89% or 0.89. So the "100-watt Module" will typically operate at about 85 Watts (95 Watts x 0.89 = 85 Watts) in the middle of a spring or fall day, under full sunlight conditions.*
>
> *Dirt and dust*
> *Dirt and dust can accumulate on the solar module surface, blocking some of the sunlight and reducing output. Much of California has a rainy season and a dry season. Although typical dirt and dust is cleaned off during every rainy season, it is more realistic to estimate system output taking into account the reduction due to dust buildup in the dry season. A typical annual dust reduction factor to use is 93% or 0.93. So the "100-watt module" operating with some accumulated dust may operate on average at about 79 Watts (85 Watts x 0.93 = 79 Watts).*

The CEC's annual dust reduction factor of 0.93 from soiling acknowledges that rain performs some washing; otherwise the factor might be lower. It is possible that losses may exceed seven percent, as appeared to be the case for one SGIP PV system. A 10 percent reduction in array power output has been reported after pollution accumulation *over four years*. The array in question is at an angle of 30 degrees from horizontal and sits atop a three-story building adjacent to a main rail line in urban Germany[2]. Reductions of greater than 10 percent from soiling are not unknown in the Central Valley in summer. The Sacramento Municipal Utility District reported performance losses of at least 10 percent on a utility-scale system near Davis during the summer of 1996[3]. On a lower end of photovoltaic performance reductions, Sandia National Laboratories report a 'soiling factor' in their performance model of "not less than 0.95 unless the array is visually quite dirty."[4] The CEC's 2001 guide to PV systems recommends washing when soiling is observbable[1]:

> *3.2.4. Maintenance and Operation Phase*
> *1. Wash PV array, during the cool of the day, when there is a noticeable buildup of soiling deposits.*

---

[2] Gradual Reduction of PV Generator Yield Due to Pollution, Haeberlin, H., and J.D. Graf, 2nd World Conference on Photovoltaic Solar Energy Conversion, Vienna, Austria, 1998.

[3] *PVUSA Quarterly Technical Report*, 3rd Quarter 1996, Pvusa Project Staff, PG&E Research and Development Department, DOE/AL/82993-31, page 26.

[4] *Photovoltaic Array Performance Model,* David L. King, William E. Boyson, and Jay A. Kratochvil, Sandia National Laboratories, Photovoltaic System R&D Department, August 2004, page 32

As described in Section 9 of this report, most (67%) of PV system owners interviewed reported that they do clean their modules. The most commonly reported frequency for cleaning was twice a year. Most system owners reported using their own staff or maintenance crew to clean the modules, while six reported hiring an independent contractor to do the job. Very large arrays or arrays that are difficult to access could be labor-intensive to clean. One of the most common reasons given for not cleaning the modules was that it was cost-prohibitive. Another reason for not cleaning was that the rain "takes care of it." Rain indeed appears to influence performance as this Appendix describes. It is not clear that reliance upon rain alone or the visibility of soiling is a cost-effective approach to module washing.

A.3 Data Sources

Secondary data sources and proxy data were utilized for this examination. No site-specific plane-of-array insolation or module temperature or rain data were collected under the scope of work for the program evaluation.

The examination of soiling used PV power output data gathered from over 100 SGIP sites. Not all of these sites had complete years of data including the rainy season. The weather data was obtained from the California Irrigation Management Information System (CIMIS). The CIMIS weather stations provided hourly insolation and precipitation data necessary for defining clear days and rain events, as well as dry bulb ambient temperature. One of 126 active CIMIS weather stations was assigned to each PV site. Typically this was the station nearest the site, but proximity of water bodies or mountains that could affect insolation and rain influenced assignment. An inland station thus might not be assigned to a coastal PV site despite being closest. Most stations were within 30 miles of the PV site and many were within 10 miles. Several CIMIS stations were excluded from assignment due to large data anomalies.

Survey data indicating PV module cleaning practices were not complete or compiled when the examination was undertaken. Some anecdotal data and photo evidence were available on module cleaning activities for a few sites.

A.4 Analytic Methodology

Confounding Issues

Given available data, the examination faced several confounding issues. Foremost were the vagaries of weather and the possibility of incorrectly associating observed power output with rain or bright sun observed elsewhere. Given the variability of rainfall over distance, rain measured at CIMIS stations may not actually fall on PV sites to which they were assigned.

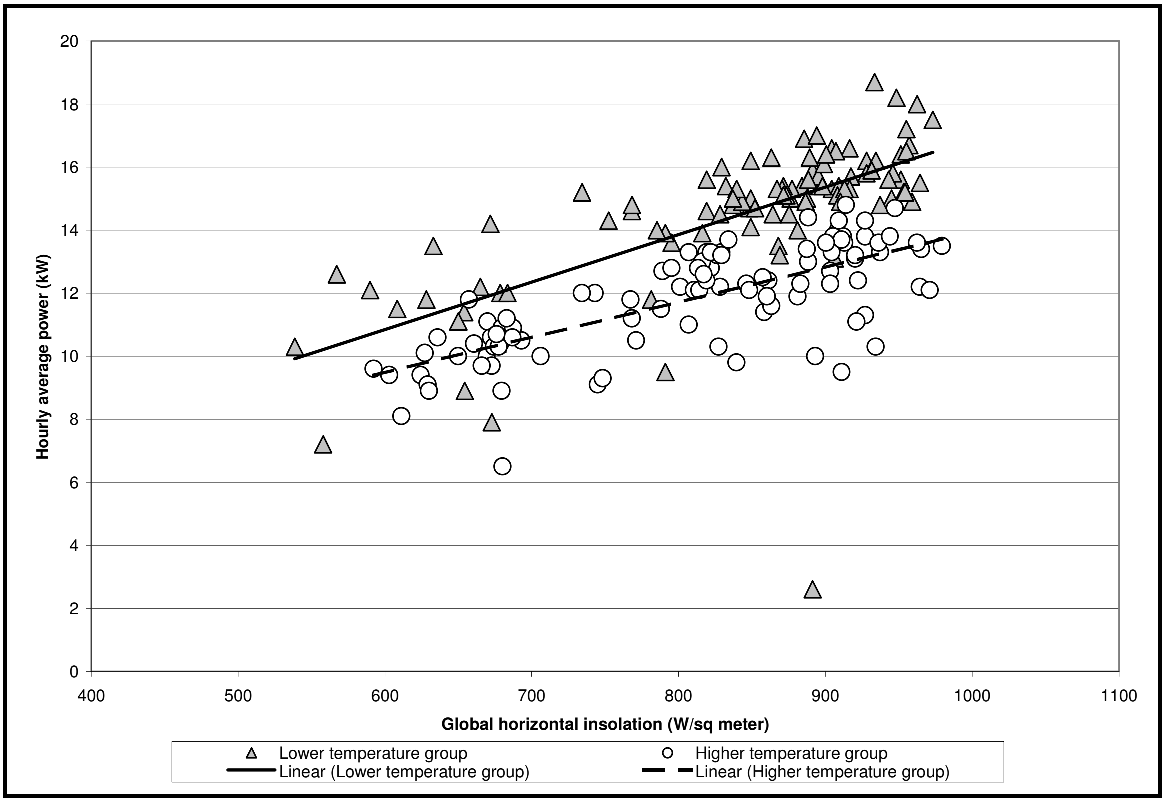
To address this issue the examination was limited to substantial accumulations of rain and the clearest days of each month when weather was more likely to be pervasive over a large area. A rain wash event was defined as an accumulation of three-quarters of an inch or more of rain in a single day or an average of one-half an inch per day over several days of continued rain. A clear day was defined as one whose total global horizontal insolation (kWh per square meter) was in the upper quartile of daily insolation totals for that month.

Another challenging issue was that absolute power output from most arrays increases from summer to winter despite whatever soiling may accumulate after the winter rainy season. To account for seasonally coincident increases in global horizontal insolation and absolute power output, daily total energy outputs (kWh) for a PV system were normalized against daily total insolation per unit area (kWh per square meter). This normalized energy output is a system-specific performance measure that can be expected to decline with soiling regardless of changes in absolute power output.

The normalization of daily energy output to account for seasonal insolation variations did not account for the influence of seasonal variation on module temperature. Absolute energy output increases from winter to summer but normalized output declines due to higher module temperatures reducing PV conversion efficiency. Figure A-1 shows this temperature dependence of power output by plotting observed hourly average power against global horizontal radiation for bins of low and high ambient temperatures used as proxies for module temperature. The plot shows a linear trend line for each temperature bin. Output is generally higher at lower temperatures for similar levels of solar radiation. Any performance reduction due to soiling had to be distinguished from influences of module temperatures. Module temperature was accounted for in the examination by including as an independent variable the CIMIS station's single hottest hourly average temperature for each clear day examined.

Although the performance reductions of higher module temperatures are mitigated by convective cooling from whatever wind may blow over or under the modules, windspeed was not included as a variable. CIMIS station windspeed data was considered but excluded due to the great dependence of windspeed at a PV site on structural features such as building parapets that may block the wind.

Figure A-1 Dependency of Power Output on Temperature



Another difficult issue was the rate of soiling and its potential for non-linearity. Debris can build up quickly but only so deep before it tends to slide or be blown off a module in light winds. Complete occlusion to the point of zero power output on a bright summer day would be rare even over many dry years. This depends of course upon the nature of the soiling. More inert debris such as cinders, paint, and pigeon excrement observed at some SGIP PV sites might be expected to reduce output from modules to very near zero. It is possible then that the maximum reduction in normalized power output might occur within just weeks of a rain wash event. Thereafter normalized output might be low but steady. A linear model was used in the examination despite the potential non-linear accumulation of soiling.

Another confounding issue was how to treat observed sudden increases in normalized output. It is not known which PV sites have washing regimens or automated washing systems that could remove soiling and cause such increases in output. Other causes could be at work too, such as correction of electronics problems or even the addition of more modules. Such improvements are known to have occurred at a number of PV sites. A linear model was used in the examination despite the potential non-linear effects of manual washing or system repairs.

Another seasonal performance issue, though unrelated to soiling, is the effect of seasonal variation in module shading. Differential shading can result from changes in angle of incidence from season to season, nearby structures possibly becoming obstructions in winter mornings and afternoons when the sun is lower. Deciduous trees may reduce summer performance relative to winter performance when leaves are off. PV array siting often requires compromises regarding differential shading. A broad assumption was made that system designers have chosen PV sites such that effects of shading have been minimized.

In light of these issues a better assessment of the impacts of soiling, washing, and rain impacts would employ precipitation, insolation, module temperature, and windspeed measures taken immediately adjacent to a sample of PV arrays. Nevertheless, here the issues have been addressed by identifying trends in normalized output for individual PV sites. These values have been examined over time and at different daily peak ambient temperatures. The conclusions herein thus account for these confounding issues to a large degree given the available data.

Performance Model

A model was posited to describe PV system performance in terms of ambient temperature and time since a last substantial rain fall. Higher ambient temperatures explain decreased performance due to higher module temperatures and corresponding lower electrical conversion efficiency. Longer times since a rainfall explain decreased performance due to accumulated soiling. PV system performance itself was defined as a quotient of daily electrical energy output over daily solar energy input, normalized per unit of system rebated capacity. This quotient allowed comparison of performance within and between PV systems regardless of the amount of solar input or system size, defined as rebated capacity. Daily performance was calculated as:

Equation 1 PV System Performance

$$P_{sd} = \frac{\left(\dfrac{\sum_{h_r}^{h_s} \left(NGO_{pdh} \right)}{\sum_{h_r}^{h_s} \left(GHR_{pdh} \right)} \right)}{S_s}$$

Where:

P_{sd}	=	PV system performance for system *s* during day *d*
		Units: square meter per kW
h_r	=	Sun rise hour, hour beginning 5 am

h_s = Sun set hour, hour beginning 9 pm

NGO_{sdh} = Metered net generator output for system *s* on day *d* during hour *h*
Units: kWh

GHR_{sdh} = Global horizontal radiation from the sun assigned to system *s* on day *d* during hour *h*
Units: kWh per square meter

S_s = System size for system *s*
Units: kW

The model estimated system performance as a function of the maximum observed temperature for a clear day and the number of days since a rain wash event. The model statement is:

Equation 2 Performance as Function of Temperature and Days since Rain

$$P_{sd} = C_s + T_s \times F_{sd} + W_s \times D_{sd}$$

Where:

C_s = Regression constant for system *s*

T_s = Regression parameter on maximum daily temperature for system *s*

F_{sd} = Maximum hourly ambient temperature for system *s* for system *s* on day *d*

W_s = Regression parameter on days since wash for system *s*

D_{sd} = Number of days since rain wash event for system *s* on day *d*

A.5 Results

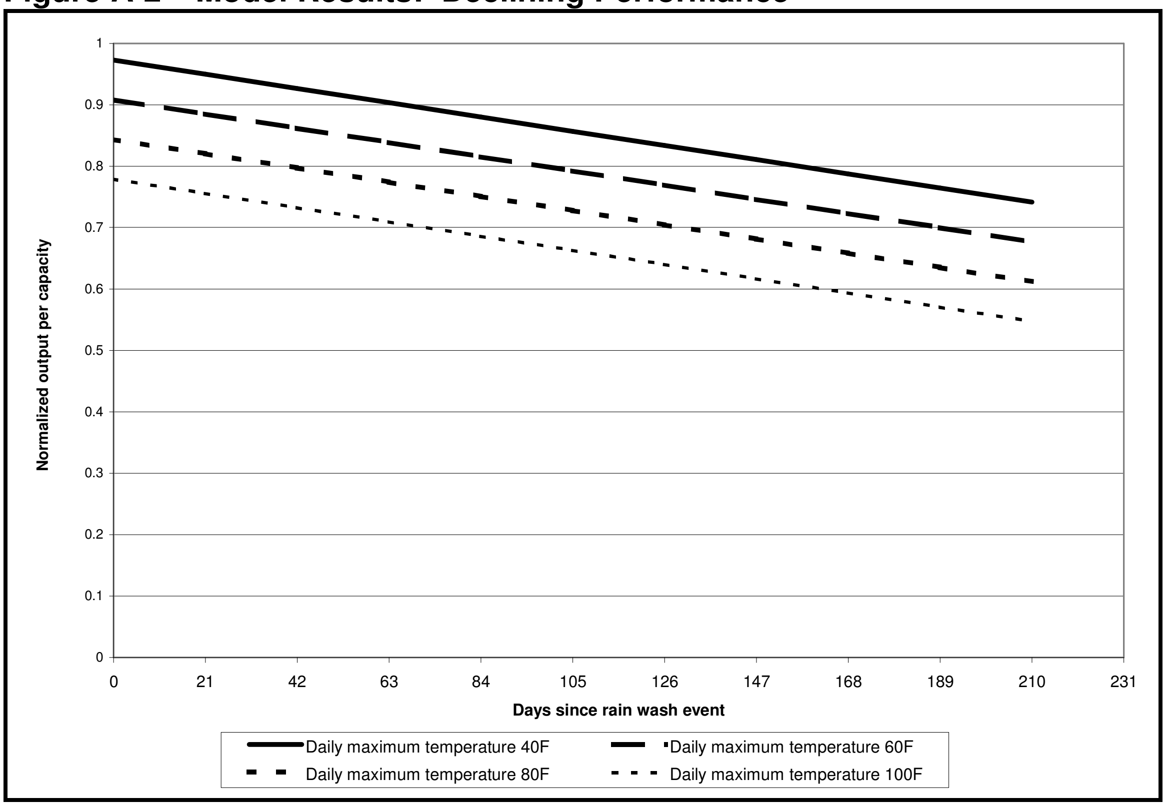
The model showed significant results (t-statistics of at least 2 for each parameter) for 24 percent of 82 PV systems categorized as having near-flat tilts, and for 26 percent of 39 systems categorized as having tilts greater than 20 degree from horizontal.

Given the limited number of complete years of and uncertainties associated with the observed energy data, the model delivered a good fit for many systems. It is noteworthy that systems with significant results from the model included not only those with declining performance with time since a last rain wash. Some systems had steady performance with time since wash, while others had improving performance. Those with improving performance may be systems whose owners wash them.

An unexpected result from the model was a number of systems with significant results whose performance improved with ambient temperature. This does not agree with known PV characteristics. The cause may be the model's use of ambient temperature as a proxy for actual module temperature. Actual module temperature is influenced by convective cooling from local winds. Modules plumbed with spray-cooling systems also can operate at temperatures largely unrelated to ambient temperatures, and so could exhibit such unexpected results. Like washing, the value of performance benefits from spray cooling is not well defined.

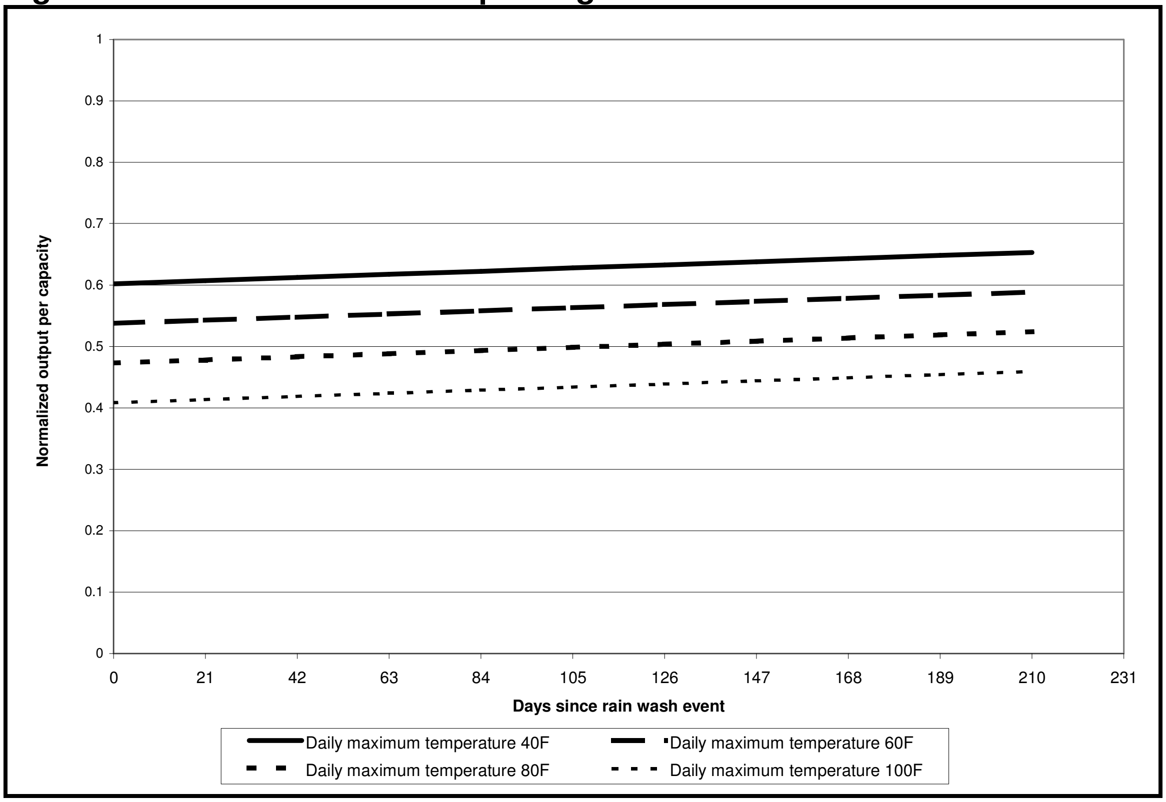
Given the limited number of complete years of and uncertainties associated with the observed energy data, the model delivered a good fit for many systems. Figure A-2 shows a plot of one system's model result. A curve is plotted for each of four values of maximum daily ambient temperature in degrees Fahrenheit. This plot indicates performance declines substantially as the number of days since a rain wash occurs. It also shows that performance declines as higher ambient temperatures contribute to higher module temperatures.

Figure A-2 Model Results: Declining Performance



Not all PV systems with significant model results showed declining performance with increasing time since a last rain wash. Figure A-3 shows a model result wherein performance improved despite increasing number of days since a rain wash. This may have been a system with little soiling, or with regular washing such that time since rain did not influence performance. As in the earlier figure, Figure A-3 also shows that performance declines as higher ambient temperatures contribute to higher module temperatures.

Figure A-3 Model Results: Improving Performance



A.6 Conclusions and Recommendations

The relationship between PV system performance and soiling has been found to be potentially significant and warrants additional research. The original scope of work for this evaluation did not include data collection to identify this phenomenon. However, current survey questionnaires and data collection practices have yielded significant data to support several aspects of this analysis. Recommendations that would further support quantification of soiling and washing effects are described below.

Participants who claimed in the telephone survey to wash their panels should be re-surveyed to determine approximate (if not exact) dates of the washing. Periodic follow-up calls should be made to determine if the panels were washed during an interval. This would assist in determining with certainty the effects of washing events.

Test sites should be recruited for case studies. There are currently several locations that have multiple systems serving the same site. These systems are similar in design and, therefore, will have very similar if not identical theoretical efficiencies. Additionally, they are subject to similar temperatures, winds, dust, and other environmental variables that influence PV production. These case study sites could undergo systematic washing of modules by the evaluation team to determine performance effects with much greater certainty. Alternative washing methods can also be examined to determine the most effective strategy based upon soiling conditions. This information would benefit the cost effectiveness of the program and provide a valuable resource to the program participants.

Appendix B

Interview Guide – System Owners

Self-Generation Incentive Program
Fourth Year Impact Evaluation
Interview Guide for System Owners

FIRM NAME:____________________ CONTACT: ___________________________
PHONE #: _______________________ TITLE: _______________________________
DATE___________________________ INTERVIEWER: _______________________

Introduction

[Once contact is on the phone]
Hello, my name is ______________. I work for Itron, and we are evaluating the Self-Generation Incentive Program. I'd like to ask you some questions about your system performance. This discussion is for research purposes only; your specific responses will be kept confidential and will not affect the incentive application status of the project(s) you are involved with. Do you have a few minutes now?

If respondent questions the legitimacy of the survey, give them Pierre Landry's contact information:
Pierre Landry
Southern California Edison
626-302-8288
Pierre.Landry@sce.com

System Performance

1. Our records show your system was off-line during the period ____________.

   a) What was the reason your system was off-line? (probe for intentional shutdown versus equip. failure and nature of problem)

   b) Is the situation expected to recur?

   c) Have you done anything to remedy the situation and bring the system back on line?

   d) If yes, please describe what you did.

Cogeneration

2. Design documentation submitted with your SGIP application indicated a capacity factor of ____% was expected. During 2004, your system's capacity factor was _____%.

   a) Did you know that your actual capacity factor in 2004 was ___% less than expected?

   b) Do you know why?
      – System operations variance (e.g., operating hours)
      – System design problem

- Mechanical failure
- Controls problems
- Natural gas relatively expensive compared to utility price of electricity
- Other

c) Do you expect your capacity factor to be higher in future years?

d) If yes, Why?

3. Design documentation submitted with your SGIP application indicated a heat recovery rate of XX_____ kBtu/kWh was expected. During 2004 the actual heat recovery rate was closer to YY____ kBtu/kWh.

a) Did you know that the actual heat recovery rate in 2004 was ZZ___% less than the expected heat recovery rate?

b) Do you know why?

- System operations variance (e.g., operating hours)
- System design problem
- Overestimate of available useful heat
- Under-estimate of host facility heat loads
- Mechanical failure
- Controls problems
- Other

c) Do you expect the heat recovery rate to be higher in future years?

d) If yes, Why?

If respondent has an absorption chiller and reports mechanical or control problems, ask the following:

e) Was the problem with rebated hardware or ineligible hardware?

4. A general rule of thumb estimate of annual routine maintenance costs for [microturbine]/[internal combustion] systems is [2.0 cents/kWh for microturbine]/[1.5 cents/kWh for internal combustion] (modify for ICN or MT). For your system this would correspond to approximately $XX____ for 2004.

a) In 2004 would you say your out-of-pocket (outside of warranty) maintenance expenditures were about this amount, or was it more or less?

b) (if answer was more or less) Would you say that was much more (or much less)?

c) What do you think was the reason for the discrepancy?

5. a) What have been your most significant non-routine maintenance costs to date?

- Replace burners
- Replace compressor

- Replace heat exchanger
- Replace compressor motor
- Replace engine heads
- Modify heat recovery piping
- Other

b). How much ($) was your company out-of-pocket for these expenses?

6. a) Do you expect maintenance costs to be similar or different (higher or lower) in future years?

b) Would you say that was much higher (or much lower)?

c) Why do you expect maintenance costs to be different?

7. a) Do you obtain your gas from a utility or through a wholesale contract from a non-utility provider?

Ask only if respondent answers utility and is a PG&E customer:

b) What rate schedule are you under?

If respondent is a non-utility provider:

c) What is your fuel cost? (quantify typical $/unit if possible)

d) What is your term of agreement in years?

e) Is the $/therm fixed or variable (i.e., tied to an index)

Photovoltaic

Ask only if capacity factor is outside of range:

8. 75% of the PV systems rebated by the SGIP had a capacity factor of between ___% and ____% in 2004. Your ___ kW PV system's capacity factor was approximately __%, which is [higher]/[lower] than what we typically observe.

a) Did you know that your capacity factor was this much different from typical?

b) Do you know why?

- Actual PV system size deviates from tracking system value
- System design problem
- Equipment failure
- Added PV modules
- Other

c) Do you expect your production to be higher in future years?

d) If yes, Why?

9. a) Do you ever clean your PV modules?

If yes:

b) When or how often?

c) How do you clean them?

d) Do you notice a difference in the system's kW output after cleaning? (If yes, Please describe.)

e) What is the approximate annual cost of this or any other routine maintenance of your PV system? [Note: if respondent owns multiple systems, specify which system (XX__kW) the $/yr applies.

f) (If they use their own staff to clean the modules and they don't offer a $ value) How many hours of labor does each cleaning require?

10. a) Have you had any unforeseen expenses due to the PV equipment that was not covered under warranty? (e.g. significant down time, roof leakage, breakage).

b) How much ($) was your company out-of-pocket for these expenses?

System Satisfaction

11. a) Was your final decision about system size and type influenced primarily by:

- an expected rate of return or payback on the investment, or
- the desire to offset a certain percentage of utility bill or
- the desire to offset a certain percentage of electrical energy usage
- other?

b) Did your system meet this expectation?

12. How satisfied are you with the system's operations to date (scale of 1 to 5, with 1 being very unsatisfied to 5 being very satisfied)?

13. How satisfied are you with the system installer's follow-up service (scale of 1 to 5, with 1 being very unsatisfied to 5 being very satisfied)?

14. a) Did you have contact with or follow-up service from your system hardware vendor or was this handled by your system installer?

b) If yes: how satisfied are you with the system hardware vendor's follow-up service, if any has been required (scale of 1 to 5, with 1 being very unsatisfied to 5 being very satisfied)?

15. Based on your experience with this system, how likely would you be to install another system like it (scale of 1 to 5, with 1 being not very likely at all, to 5 very likely)?

16. Do you have any other comments or observations regarding your generating system?

Appendix C

Comments from Participant Perspectives Interviews

This Appendix details some of the comments made during the interviews with owners of on-line SGIP PV systems. While the results of these interviews were summarized in Section 9 of this report, these comments provide additional insight into PV system operators' views on performance and maintenance issues. For the interviews with owners of cogeneration systems, comments were not recorded in a format amendable to reporting in this fashion.

Comments made by owners of PV systems during the interviews conducted for this study are arranged below under the following topic areas:

- Cleaning the solar panels,
- How well the system has met expectations,
- The likelihood of installing another PV system, and
- Other comments.

Cleaning Panels

- We've been watching the effect of the rain. (The panels) get some dust accumulation during the year, but the rain cleans them well. The rain seems to be sufficient to clean them up.
- The weather seems to do it.
- We let the rain do it.
- We rely on the rain.
- We looked into it and did tests to see how much it would change the efficiency but it was only 2% to 3%. Since we would have to hand wash the panels (just spraying water on it wouldn't be enough), it would be time consuming and expensive. So it's not worth it.
- We have never been able to clean them, because we don't have water faucets on the roof. It's installed on a four-story building so we can't get a hose up there. We don't plan to find a way to clean them.
- The system is on top of a two-story building and there's no access to the roof to clean the panels. The company that installed them said they would try to clean them but they have not done that yet.

- We used to clean them 2 to 3 times in the summer, but not any more. While it increased the output 6% to 7%, the gain only lasted a month. So the labor to clean it isn't worth it.
- We just clean it in the summer months…it looks like a 7% gain from cleaning.
- We have never cleaned them. The rain does that, right?

Meeting Expectations

- So far it's right on the money. The engineering work promised a certain amount of electrical generation. It actually generates slightly more than we expected because the panel manufacturer upgraded their product since we looked at the design of it.
- We expected a 35% drop in our bill and we're seeing a 50% drop.
- We are very satisfied. The system performs exactly as advertised.
- We are getting a 10% plus return on our money.
- We expected to offset our bill by 50%, but the bill dropped 56%.
- We are thrilled with the payback. We have no utility bill.
- It's producing 10% less than we expected.
- We haven't achieved what we thought we would, but it's pretty good.
- Well, it's hard to say. It's hard to see the usage. You don't really get a direct line on your bill that says exactly how much you're saving.
- Right on target. Within 1%.
- We are totally satisfied.

Adding another System

- We'd love to do another one but not without the rebate.
- We'd like to see the cost of the technology come down before we do another one.
- Based on budget only, we would not be likely to install another one; however, based on performance, we would. Budgets are very sensitive right now.
- We're interested in putting in another system, but the payback has to be right. If we have no incentives, the payback is 35 years. With all the incentives we got on this one the payback is six years.
- We did three in a row, but another one isn't going to happen for awhile due to budget constraints.
- We'd be very likely to consider it at the next opportunity; however, I'm not sure when that will be.

- We're frustrated because we know data is being collected on our system and we are not able to see it in a usable format. The legislature is creating incentives but we can't justify spending any more money until we know more about our system performance.
- The cost of installing a system is staying the same but the rebate is going down. So our out-of-pocket cost is going up and the payback period is going up.
- We have not been able to get statistics from our electric utility company on how well the system is performing. They have been unresponsive. Unless we get that, we're not going to do another one.
- We are not likely to put in another system. The reason is because of cost and not because of quality or performance.
- We're very likely to put in another one when we get up the cash.
- We'd be very likely if the incentives were as before. However, with the rebate declining, we're not sure. We're still looking at the economics.
- We would if we had the cash.
- We would do it again but it depends on the level of performance we can get out of the system.
- We put a second one in last year. We're going to wait a year or two until the first one is paid off, and then we'll put another one.

Other

- We're interested in seeing what the useful life of the system turns out to be. Some degradation is projected for the efficiency of the panels over time, so we'll see. We don't know if it will have a 15 or a 20 year life.
- We spent a lot of money to put this system in and now the electric utility company is charging high demand charges. We're frustrated because we're not getting what we expected out of it.
- We're struggling to read the net metered billing reports we receive.
- We're still concerned with the payback period. This system has a 23-year payback (with the rebate)…. Being in a bureaucracy adds a lot of cost to the project so it's more expensive than it is with a private company.
- It's a good environmental thing to do, producing electricity from outside sources. It is an investment and takes a few years for payback, but it does have a good environmental impact.
- We wish we had put in a bigger system.
- We're very unhappy with our utility. They cannot explain net metered billing. They make it so confusing so we can't understand it. Nobody there understands it. They send late notices that we haven't paid our bill because they haven't trained

their staff to understand what net metering is. If it wasn't for how great my installer is and how responsive they've been, I would never have gotten this done.

- We wonder how long the inverter will last. It has a five-year warranty and costs $100,000 to replace. So we want to see how well that holds up before thinking about putting in another system.
- The payback is based on the assumption that energy prices will escalate 3% a year. If they increase at a slower rate, the payback will be longer.
- We're probably in the minority, but we produce more power than we use. But there is no arrangement to reimburse us for the excess. Last year we had an excess credit of $4,000 that just got wiped off the books….We have five other accounts on this property and …it would be nice to apply that credit to our other accounts if we could.